Diane Roy
Director, Regulatory Affairs

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August 12, 2013

Via Email
Original via Mail

Randolph F. Robinson
21570 Telegraph Trail
Langley, BC
V1M 2K8

Dear Mr. Robinson:

Re: FortisBC Energy Utilities (FEU)[1]

Applications for Reconsideration and Variance of Commission Order G-26-13 Common Rates, Amalgamation, and Rate Design Decision (the Reconsideration Applications) - Phase Two

Response to Randolph F. Robinson Information Request (IR) No. 1

On June 26, 2013, the Commission issued Order G-100-13 establishing a Regulatory Timetable for Phase Two of the Reconsideration Applications. In accordance with Commission Letter L-46-13 setting out the Amended Regulatory Timetable, the FEU respectfully submit the attached response to IR No. 1 from Randolph F. Robinson.

If further information is required, please contact the undersigned.

Sincerely,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed:

Diane Roy

Attachments

cc (e-mail only): Commission Secretary
Registered Parties

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[1] Consisting of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.

1.0 Please provide the most recent segmented financial statements of the individual entities before consolidation as reported in FortisBC Holdings Inc. Consolidated Financial Statements for the years ended December 31, 2012 and 2011 . In particular, the FortisBC Energy Inc., FortisBC Energy (Whistler) Inc., and FortisBC Energy (Vancouver Island) Inc.

Note: I have already signed a confidentiality letter.

<u>Response:</u>

Please refer to Attachment 1.0A for the 2012 financial statements for FortisBC Energy Inc. Please also refer to CONFIDENTIAL Attachment 1.0B for the the financial statements for FortisBC Energy (Whistler) Inc and FortisBC Energy (Vancouver Island) Inc. All sets of financials have comparative information for 2011.

2.0 Please provide <u>the report</u> referenced in the following excerpt from FortisBC's evidence given in this matter dated July 10, 2013 titled New Evidence and reference to **Shared Services Management ReportTerasen Gas Inc. and Terasen Gas Vancouver Island May 31, 2004**

<u>The report prepared by Deloitte & Touche that presents a framework based on generally accepted methods of allocating shared services costs to affiliates (filed as part of the Terasen Corporate Separation Study, Section B, Tab 9 of the 2003 Annual Review). This report was commissioned by Terasen Inc. (TI) and used in establishing the cost allocation basis for management services provided by TI to TGI commencing January 1, 2004. The framework used as the basis for the allocation of Shared Service costs is consistent with the approach used by Terasen Inc. The British Columbia Utilities Commission (“the Commission”) approved the cost allocation fee to TGI in its Decision dated December 17, 2003 via Commission Order No. G-80-03.</u>

<u>In addition, the Company created guiding objectives for the development of cost allocation approach. These guiding objectives were to ensure:</u>

- <u>The avoidance of cross subsidization between regulated entities.</u>
- <u>The establishment of procedures that are efficient to administer and account for.</u>
- <u>The creation of a methodology that is reasonable, flexible and responsive to organizational changes.</u>

- The demonstration of a causal link between the allocation of cost and the cause of the costs incurred through the use of cost drivers.

Response:

The referenced report is provided in Attachment 2.0.

3.0 Please provide the justification for amalgamating downstream utilities, namely FEVI and FEW, that do not add value to an upstream utility, namely FEU, given any synergy in shared management resources are already being realized to the benefit of the downstream utilities. In the justification address the issue of how rate stabilization can be achieved without cross subsidization.

Response:

The FEU do not agree with the premise of the question. The synergies achieved through shared services have benefited all of the utilities through reduced costs. Therefore the downstream utilities FEVI and FEW have added value to the FEU through lower total costs than would have been the case if they were independent utilities. Amalgamation is the next step in realizing further savings for customers.

The FEU have put forward their detailed justification for the proposed amalgamation in their Common Rates, Amalgamation and Rate Design Application, submitted to the Commission in April 2012, marked as Exhibit B-3 in the original proceeding. Please see Section 4 of that Application in particular.

The extension of postage stamp rates from the FEI service territory to FEVI and FEW would result in cost-based rates that are consistent with the existing postage stamp rates in the Province and address the rate stability issues associated with the smaller utilities discussed in section 4.4 of the Common Rates, Amalgamation and Rate Design Application.

Attachment 1.0A

FortisBC Energy Inc.

An indirect subsidiary of Fortis Inc.

Consolidated Financial Statements
For the years ended December 31, 2012 and 2011

Prepared in accordance with United States Generally Accepted Accounting Principles

MANAGEMENT'S REPORT

The accompanying annual consolidated financial statements of FortisBC Energy Inc. have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These annual consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States.

In meeting its responsibility for the reliability and integrity of the annual consolidated financial statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation focus on the need for training of qualified and professional employees and the effective communication of management guidelines and policies. The effectiveness of the internal controls of FortisBC Energy Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit and Risk Committee (Audit Committee) which is composed of three independent directors and one director who is an officer of a related company. The Audit Committee oversees the external audit of the Corporation's annual consolidated financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's annual consolidated financial statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee.

The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's annual consolidated financial statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees.

The 2012 annual consolidated financial statements and Management Discussion and Analysis were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of FortisBC Energy Inc.

Ernst & Young, LLP, independent auditors appointed by the shareholders of FortisBC Energy Inc. upon recommendation of the Audit Committee, have performed an audit of the 2012 annual consolidated financial statements and their report follows.

(Signed by)
John Walker
President and Chief Executive Officer

(Signed by)
Michele Leeners
Vice President, Finance and Chief Financial Officer

Vancouver, Canada
February 5, 2013

INDEPENDENT AUDITORS' REPORT

To the Shareholders of
FortisBC Energy Inc.

We have audited the accompanying consolidated financial statements of **FortisBC Energy Inc.**, which comprise the consolidated balance sheets as at December 31, 2012 and 2011, and the consolidated statements of earnings, changes in equity and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of **FortisBC Energy Inc.** as at December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the years then ended in accordance with accounting principles generally accepted in the United States.

Ernst & Young LLP

Vancouver, Canada,
February 5, 2013.

Chartered Accountants

FortisBC Energy Inc.
Consolidated Balance Sheets (US GAAP)
As at December 31
(all amounts are in millions of Canadian dollars)

ASSETS	**2012**	2011
Current assets		
Cash and cash equivalents	**$ 22**	$ 17
Accounts receivable, net (note 4)	**205**	238
Inventories (note 5)	**95**	101
Prepaid expenses	**3**	3
Deferred income taxes (note 16)	**13**	10
Regulatory assets (note 8)	**28**	73
	366	442
Property, plant and equipment, net (note 6)	**2,604**	2,573
Intangible assets, net (note 7)	**121**	117
Goodwill (note 7)	**769**	769
Regulatory assets (note 8)	**561**	514
Other assets	**22**	23
	$ 4,443	$ 4,438
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term notes (note 19)	**$ 33**	$ 65
Accounts payable and accrued liabilities (note 9)	**226**	304
Income and other taxes payable	**32**	38
Current portion of capital lease and finance obligations (note 10)	**7**	7
Regulatory liabilities (note 8)	**35**	23
	333	437
Long-term debt (note 10)	**1,545**	1,545
Capital lease and finance obligations (note 10)	**116**	120
Regulatory liabilities (note 8)	**55**	54
Deferred income taxes (note 16)	**309**	298
Other long-term liabilities (note 11)	**194**	185
	2,552	2,639
Shareholders' equity		
Common shares[a] (note 12)	**784**	719
Additional paid-in capital	**1,019**	1,019
Retained earnings	**88**	61
	1,891	1,799
	$ 4,443	$ 4,438

[a] no par value; 500 million authorized common shares; 64.9 million issued and outstanding at December 31, 2012 and 63.0 million issued and outstanding at December 31, 2011.

Commitments and Contingencies (notes 21 and 22)

Approved on Behalf of the Board:

(Signed by) Harold Calla
Director

(Signed by) John Walker
Director

The accompanying notes are an integral part of these consolidated financial statements.

FortisBC Energy Inc.
Consolidated Statements of Earnings (US GAAP)
For the years ended December 31
(all amounts are in millions of Canadian dollars)

	2012	2011
Revenue		
Natural gas transmission and distribution	**$ 1,218**	$ 1,351
Other income	**48**	41
	1,266	1,392
Expenses		
Cost of natural gas	**605**	763
Operation and maintenance (note 20)	**196**	205
Depreciation and amortization	**128**	92
Property and other taxes	**50**	51
	979	1,111
Operating Income	**287**	281
Finance charges (note 14)	**164**	155
Earnings before income taxes	**123**	126
Income taxes (note 16)	**11**	16
Net earnings	**$ 112**	$ 110

FortisBC Energy Inc.
Consolidated Statements of Changes in Equity (US GAAP)
For the years ended December 31
(all amounts are in millions of Canadian dollars)

	Common Shares	Additional Paid-in Capital	Retained Earnings	Total Equity
As at December 31, 2010	$ 719	$ 1,020	$ 36	$ 1,775
Net earnings	-	-	110	110
Contribution to capital	-	(1)	-	(1)
Dividends on common shares	-	-	(85)	(85)
As at December 31, 2011	**719**	**1,019**	**61**	**1,799**
Net earnings	-	**-**	**112**	**112**
Issuance of common shares	**65**	**-**	-	**65**
Dividends on common shares	-	**-**	**(85)**	**(85)**
As at December 31, 2012	**$ 784**	**$ 1,019**	**$ 88**	**$ 1,891**

The accompanying notes are an integral part of these consolidated financial statements.

FortisBC Energy Inc.
Consolidated Statements of Cash Flows (US GAAP)
For the years ended December 31
(all amounts are in millions of Canadian dollars)

	2012	2011
Cash flows provided by (used for)		
Operating activities		
Net earnings	**$ 112**	$ 110
Adjustments for non-cash items		
Depreciation and amortization	**128**	92
Deferred income taxes	**(1)**	(1)
Other	**(2)**	(8)
	237	193
Changes in long-term regulatory assets and liabilities	**(31)**	(10)
Changes in non-cash working capital (note 15)	**14**	84
	220	267
Investing activities		
Property, plant and equipment	**(141)**	(139)
Intangible assets	**(19)**	(30)
Additional paid-in capital	**-**	(1)
Other assets and other long-term liabilities	**1**	5
	(159)	(165)
Financing activities		
Decrease in short-term notes	**(32)**	(113)
Increase in long-term debt	**-**	101
Reduction of capital lease and finance obligations	**(4)**	(3)
Issuance of common shares	**65**	-
Dividends on common shares	**(85)**	(85)
	(56)	(100)
Net increase in cash and cash equivalents	**5**	2
Cash and cash equivalents at beginning of year	**17**	15
Cash and cash equivalents at end of year	**$ 22**	$ 17

Supplementary Information to Consolidated Statements of Cash Flows (note 15).

The accompanying notes are an integral part of these consolidated financial statements.

1. DESCRIPTION OF THE BUSINESS

FortisBC Energy Inc. ("FEI" or the "Corporation") is a subsidiary of FortisBC Holdings Inc. ("FHI"), which is a wholly owned subsidiary of Fortis Inc. ("Fortis"), a Canadian public company.

FEI is the largest distributor of natural gas in British Columbia ("BC"), serving approximately 841,000 residential, commercial and industrial customers in more than 100 communities. Major areas served by the Corporation are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of the province. The Corporation provides transmission and distribution services to its customers, and obtains natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern BC and, through the Corporation's Southern Crossing Pipeline, from Alberta.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in the United States ("US GAAP") for annual financial statements and in accordance with Regulation S-X promulgated by the Securities and Exchange Commission ("SEC"). The consolidated financial statements include the accounts of the Corporation and its subsidiary. All material inter-company transactions and balances have been eliminated upon consolidation except for those inter-company transactions recovered in rates from customers.

An evaluation of subsequent events through February 5, 2013, the date these consolidated financial statements were available to be issued, was completed to determine whether any circumstances warranted recognition and disclosure of events or transactions in the consolidated financial statements as at December 31, 2012. There were no subsequent events to report.

Certain comparative figures have been reclassified to conform to the current year's presentation.

Regulation

The Corporation is regulated by the British Columbia Utilities Commission ("BCUC"). Pursuant to the *Utilities Commission Act* (British Columbia), the BCUC regulates such matters as tariffs, rates, construction, operations, financing and accounting.

The Corporation's consolidated financial statements have been prepared in accordance with US GAAP, including certain accounting treatments that differ from that for enterprises not subject to rate regulation. The impacts of rate regulation on the Corporation's operations for the years ending December 31, 2012 and 2011 are described in these "Summary of Significant Accounting Policies", and in note 6 "Property, Plant and Equipment", note 7 "Goodwill and Intangible Assets", note 8 "Regulatory Assets and Liabilities", note 13 "Employee Future Benefits", note 14 "Finance Charges", and note 16 "Income Taxes".

When the BCUC issues decisions affecting the financial statements, the effects of the decision are recorded in the period in which the decision is received.

In April 2012, FEI, FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC (Whistler) Inc. ("FEW") received a decision from the BCUC on its 2012/2013 Revenue Requirements Application ("2012/2013 RRA"). The decision resulted in a cost of service based methodology and covers the years 2012 and 2013. During 2012 and 2011 the Corporation earned an allowed rate of return that was based on a deemed debt-equity ratio of 60 per cent debt and 40 per cent equity and a return on equity ("ROE") of 9.5 per cent.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term deposits with maturities of three months or less from the date of deposit.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of losses on the accounts receivable balances. The Corporation maintains an allowance for doubtful accounts that is estimated based on a variety of factors including accounts receivable aging, historical experience and other currently available information, including events such as customer bankruptcy and current economic conditions. Interest is charged on overdue accounts receivable balances. Accounts receivable are charged-off in the period in which the receivable is deemed uncollectible.

Regulatory Assets and Liabilities

The BCUC has the general power to include or exclude costs, revenues, losses or gains in the rates of a specified period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. Regulatory assets represent future revenues associated with certain costs incurred that will be, or are probable to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

The Corporation currently employs deferral accounts to address uncontrollable or non-routine items and to match costs incurred to the periods that the costs benefit. Two primary deferral mechanisms currently in place decrease the volatility in rates caused by such factors as fluctuations in gas supply costs and the significant impacts of weather and other changes on use rates. The first mechanism relates to the recovery of all gas supply costs through deferral accounts that capture variances (overages and shortfalls) from forecasts in costs incurred. Balances are either refunded to or recovered from customers via quarterly review and application to the BCUC. Currently under this mechanism, there are two separate deferral accounts: the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA"). The second mechanism seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use rate throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism ("RSAM").

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the BCUC could alter the amounts subject to deferral, at which time the change would be reflected in the consolidated financial statements. For regulatory assets and liabilities which are amortized, the amortization is approved by the BCUC. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Inventories

Inventories of gas in storage are valued at weighted average cost. The cost of gas in storage is recovered from customers in future rates.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions in aid of construction. Cost includes all direct expenditures for system expansions, betterments and replacements and as prescribed by the BCUC an allocation of overhead costs and an allowance for funds used during construction. When allowed by the BCUC, regulated operations also capitalize an allowance for equity funds used during construction at approved rates.

Depreciation is based on rates approved by the BCUC and is calculated on a straight-line basis on the investment in property, plant and equipment when the property, plant and equipment goes into service.

As approved by the BCUC, gains and losses on the sale or removal of property, plant and equipment are recorded in a regulatory deferral account on the consolidated balance sheet for refund to, or recovery from, customers in future rates, subject to regulatory approval.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Property, Plant and Equipment (continued)

Prior to 2012, estimated removal costs were recorded as part of operation and maintenance expense with variances versus forecast being recorded in a regulatory deferral account for recovery from, or refund to, customers in future rates starting in 2012. In the 2012/2013 RRA, the Corporation applied for and received approval to collect removal costs as a component of depreciation on an accrual basis, with actual removal costs incurred drawing down the accrual balance. Removal costs are the direct costs incurred by the Corporation in taking assets out of service, whether through actual removal of the asset or through disconnection from the transmission or distribution system.

Intangible Assets

Intangible assets are comprised of right of ways and software not directly attributable to the operation of property, plant and equipment and are recorded at cost less accumulated amortization and unamortized contributions in aid of construction. Included in the cost of intangible assets are all direct expenditures, betterments and replacements and as prescribed by the BCUC, an allowance for funds used during construction. When allowed by the BCUC, regulated operations also capitalize an allowance for equity funds used during construction at approved rates.

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite lives are amortized over their useful lives and assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization rates for regulated intangible assets are approved by the BCUC.

Intangible assets with indefinite useful lives are not subject to amortization and are tested for impairment annually or more frequently if events or changes in circumstances indicate the asset may be impaired. The useful life of an intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

Effective January 1, 2012, the Corporation early adopted the amendments to Accounting Standards Codification ("ASC") Topic 350, *Intangibles - Goodwill and Other* ("ASC Topic 350") as discussed in this note under the heading "Changes in Accounting Polices".

Commencing in 2012, the determination of the approach for assessing impairment of indefinite-lived intangible assets is consistent with the approach taken for the purposes of goodwill impairment testing, as discussed further in this note under "Goodwill". No impairment provision has been determined for the years ended December 31, 2012 and 2011.

The Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of the indefinite-lived intangible assets was below its carrying value.

As approved by the BCUC, gains and losses on the sale or removal of intangible assets are recorded in a regulatory deferral account on the consolidated balance sheet for refund to, or recovery from, customers in future rates, subject to regulatory approval.

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset and eventual disposition.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Impairment of Long-Lived Assets (continued)

If the carrying amount of an asset exceeds its estimated future cash flows and eventual disposition, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset.

Asset-impairment testing is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets' carrying value, including a fair return on capital assets, is provided through customer rates approved by the BCUC. The net cash inflows for the Corporation are not asset-specific but are pooled for the entire regulated utility. There was no impairment of long-lived assets for the years ended December 31, 2012 and 2011.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment.

Effective January 1, 2012, the Corporation adopted the amendments to ASC Topic 350 related to the testing for impairment of goodwill. The amended standard allows entities testing goodwill for impairment to have the option, on an annual basis, of performing a qualitative assessment before calculating fair value. If the qualitative factors indicate that fair value is 50 per cent or more likely to be greater than the carrying value, calculation of fair value would not be required.

Prior to adopting amendments to ASC Topic 350, fair value was estimated by an independent external consultant on an annual basis. Upon adopting the above-noted amendments, the Corporation performs an annual internal quantitative assessment and fair value is estimated by an independent external consultant when: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50 per cent or more likely to be greater than carrying value; or (ii) when the excess of estimated fair value compared to carrying value, as determined by an independent external consultant as of the date of the immediately preceding impairment test, was not significant. Irrespective of the above-noted criteria, the Corporation will have fair value estimated by an independent external consultant, as at the annual impairment date, at a minimum once every three years.

The Corporation performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of the goodwill was below its carrying value. No such event or changes in circumstances occurred during 2012 or 2011 and there were no impairment provisions required in either year.

As at October 1, 2012, the fair value of the Corporation was estimated by an independent external consultant and estimated fair value was determined to be in excess of carrying value. It was concluded that goodwill was not impaired.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Asset Retirement Obligations

The Corporation will recognize the fair value of a future Asset Retirement Obligation ("ARO") as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. The Corporation will concurrently recognize a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset. The fair value of the ARO is to be estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted, risk-free interest rate. Subsequent to the initial measurement, the ARO will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

Changes in the obligation due to the passage of time are to be recognized in income as an operating expense using the effective interest method. Changes in the obligation due to changes in estimated cash flows are to be recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

As the fair value of future removal and site restoration costs for the Corporation's natural gas transmission and distribution systems are not currently determinable as they will be used in perpetuity, the Corporation has not recognized an ARO as at December 31, 2012 and 2011. For regulated operations there is a reasonable expectation that asset retirement costs will be recoverable through future rates.

Revenue Recognition

Natural gas transmission and distribution revenue is billed at rates approved by the BCUC and is bundled to include the cost of transmitting and distributing natural gas. In addition the rate includes customer service as well as other corporate and service functions.

Revenues from natural gas sales are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year and are adjusted for the RSAM and other BCUC approved orders. Natural gas that is consumed but not yet billed to the customers is estimated and accrued as revenue at each reporting date. The estimation process for unbilled natural gas consumption will result in adjustments to estimates of natural gas transmission and distribution revenues in the periods they become known.

Employee Future Benefits

The Corporation sponsors a number of employee post-employment benefit plans. These plans include defined benefit, unfunded supplemental, and various other post-retirement benefit ("OPEB") plans.

These plans are accounted for pursuant to ASC Topic 715, *Compensation-Retirement Benefits*. The cost of pensions and OPEBs earned by employees are actuarially determined as an employee accrues service. The Corporation uses the projected benefit pro-rate method based on years of service, management's best estimates of expected returns on plan assets, salary escalation, retirement age, mortality and expected future health-care costs. The discount rate used to value liabilities is based on Corporate AA bond yields with cash flows that match the timing and amount of the expected benefit payments under the plans. The Corporation uses a measurement date of December 31 for all plans.

The expected return on plan assets is based on management's estimate of the long-term expected rate of return on plan assets and a market-related value of plan assets. The market-related value of assets is determined using a smoothed value that recognizes investment gains and losses gradually over a three year period.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Employee Future Benefits (continued)

Adjustments, in excess of 10 per cent of the greater of the accrued benefit obligation and the fair value of plan assets that result from changes in assumptions and experience gains and losses, are amortized straight-line over the expected average remaining service life of the employee group covered by the plans. Experience will often deviate from the actuarial assumptions resulting in actuarial gains and losses.

The Corporation records the funded or unfunded status of its defined benefit pension plans and OPEB plans on the balance sheet. Unamortized balances relating to past service costs and net actuarial gains and losses have been recognized in regulatory assets and are expected to be recovered from customers in future rates. Subsequent changes to past service costs and net actuarial gains and losses are recognized as an expense, where required by the BCUC, or otherwise as a change in the regulatory asset or liability.

Derivative Financial Instruments and Hedging Activities

The Corporation hedges exposures to fluctuations in natural gas prices through the use of derivative instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes. As at December 31, 2012, the Corporation's derivative contracts consisted of forward physical purchase and sales contracts and natural gas derivative contracts.

The natural gas derivative contracts are recorded at fair value. Any unrealized losses or gains, to the extent that they are recoverable through regulated rates, associated with the change in fair value of these contracts and realized losses or gains associated with the settlement of these contracts, are deferred as a regulatory asset or regulatory liability. As such, these contracts have not been designated as qualifying accounting hedges, but rather serve as economic hedges. Generally, the Corporation limits the use of derivative instruments to those that qualify as accounting or economic hedges. Should the BCUC no longer allow the deferral of unrealized losses or gains as regulatory assets or liabilities, the Corporation would designate these contracts as a qualifying cash flow hedge and, to the extent that the cash flow hedges are effective, the unrealized losses or gains would be recognized in accumulated other comprehensive earnings, net of taxes.

Fair Value Measurement

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party at the measurement date, or the "exit price". A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. The Corporation utilizes a fair value hierarchy that prioritizes the inputs used to measure fair value and gives precedence to observable inputs in determining fair value. An instrument's level within the hierarchy is based on the lowest level of any significant input to the fair value measurement. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements) (see note 18).

Finance Charges

Costs incurred to arrange debt financing are recognized as other assets and are accounted for using the effective interest method over the life of the related financial liability.

Sales Taxes

In the course of its operations, the Corporation collects sales taxes from its customers. When customers are billed, a current liability is recognized for the sales taxes included on the customer's bill. This liability is settled when the taxes are remitted to the appropriate government authority. The Corporation's revenue excludes the sales taxes.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Income Taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are more likely than not (greater than a 50 per cent chance) to be realized. The deferred income tax assets and liabilities are measured using enacted income tax rates and laws that will be in effect when the temporary differences are expected to be recovered or settled. As a result of rate regulation, deferred income taxes incurred related to regulated operations have been offset by a corresponding regulatory asset or liability resulting in no impact on net earnings. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the BCUC, the Corporation recovers income tax expense in customer rates based only on income taxes that are currently payable for regulatory purposes, except for certain regulatory asset and liability accounts specifically prescribed by the BCUC. Therefore, current customer rates do not include the recovery of deferred income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in rates when they become payable. An offsetting regulatory asset or liability is recognized for the amount of income taxes that are expected to be collected in rates once they become payable.

Any difference between the expense recognized under US GAAP and that recovered from customers in current rates for income tax expense that is expected to be recovered, or refunded, in future customer rates is subject to deferral treatment as described in note 8 "Regulatory Assets and Liabilities".

The Corporation recognizes a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50 per cent likely to be realized upon settlement. The difference between a tax position taken or expected to be taken in a tax return and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Interest and penalties related to unrecognized tax benefits are recognized in income tax expense.

Variable Interest Entities

The Corporation has performed a review of the entities with which it conducts business and has concluded that there are no entities that are required to be consolidated or variable interests that are required to be disclosed under the requirements of ASC Topic 810, *Consolidation of Variable Interest Entities.*

Use of Estimates

The preparation of the Corporation's financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, regulatory decisions, current conditions and various other assumptions believed to be reasonable under the circumstances. The use of estimates are described in these "Summary of Significant Accounting Policies", in note 8 "Regulatory Assets and Liabilities" and note 22 "Contingencies". Certain estimates are also necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

CHANGES IN ACCOUNTING POLICIES

The following new US GAAP accounting pronouncements that are applicable to, and were adopted by, the Corporation effective beginning January 1, 2012 are described as follows:

Presentation of Comprehensive Income

The Corporation adopted the amendments to ASC Topic 220, *Comprehensive Income.* The amended standard requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements.

Testing Goodwill and Indefinite-Lived Intangible Assets for Impairment

The Corporation adopted the amendments to ASC Topic 350 related to the testing for impairment of goodwill and early adopted the amendments related to testing for impairment of indefinite-lived intangible assets. The amended standard allows entities testing goodwill and indefinite-lived intangible assets for impairment to have the option, on an annual basis, of performing a qualitative assessment before calculating the fair value. If the qualitative factors indicate that the fair value is 50 per cent or more likely to be greater than the carrying value, calculation of fair value would not be required. Previous guidance in ASC Topic 350 required an entity to test goodwill and indefinite-lived intangible assets for impairment, on at least an annual basis, by calculating their fair value and comparing it to carrying value. If the carrying value exceeds fair value, an impairment charge is required. As at October 1, 2012, the fair value of the Corporation was estimated by an independent external consultant and estimated fair value was determined to be in excess of carrying value. It was concluded that goodwill as well as the indefinite-lived intangible assets of the Corporation were not impaired.

Fair Value Measurement

The Corporation adopted the amendments to ASC Topic 820, *Fair Value Measurements and Disclosures.* The amended standard improves comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with US GAAP. The amendment does not change what items are measured at fair value but instead makes various changes to the guidance pertaining to how fair value is measured.

The above-noted changes did not materially impact the Corporation's consolidated financial statements for the years ended December 31, 2012 and 2011.

Change in Accounting Policy as a Result of Regulatory Applications

Effective January 1, 2012, as applied for in its 2012/2013 RRA and approved by the BCUC, the Corporation adopted the following new accounting policy on a prospective basis:

> Prior to 2012, estimated removal costs were recorded as part of operation and maintenance expense with variances versus forecast being recorded in a regulatory deferral account for recovery from, or refund to, customers in future rates starting in 2012. In the 2012/2013 RRA, the Corporation applied for and received approval to collect removal costs as a component of depreciation on an accrual basis, with actual removal costs incurred drawing down the accrual balance. Removal costs are the direct costs incurred by the Corporation in taking assets out of service, whether through actual removal of the asset or through disconnection from the transmission or distribution system.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

FUTURE ACCOUNTING PRONOUNCEMENT

Disclosures About Offsetting Assets and Liabilities

Effective January 1, 2013, the Corporation adopted the amendments to ASC Topic 210 *Balance Sheet - Disclosures About Offsetting Assets and Liabilities* as outlined in Accounting Standards Update ("ASU") No. 2011-11. The amendment improves the transparency of the effect or potential effect of netting arrangements on a company's financial position by expanding the level of disclosures required by entities for such arrangements. The amended disclosures are intended to assist financial statement users in understanding significant quantitative differences between balance sheets prepared under US GAAP and International Financial Reporting Standards.

The Corporation does not expect these changes to have a material impact on its consolidated financial statements.

3. REGULATORY MATTERS

Allowed ROE and Capital Structure

In February 2012, the BCUC established a Generic Cost of Capital ("GCOC") Proceeding would occur and in April 2012, issued a final scoping document identifying specific items that would be reviewed as part of the GCOC Proceeding, including:

- the appropriate cost of capital for a benchmark low-risk utility effective January 1, 2013. Cost of capital includes capital structure, return on common equity and interest on debt;
- the establishment of a benchmark ROE based on a benchmark low-risk utility effective January 1, 2013 to December 31, 2013 for the initial transition year;
- if it is determined through the GCOC Proceeding that a return to an ROE automatic adjustment mechanism ("AAM") is warranted it would be implemented January 1, 2014. If not, a future regulatory process would be set to review the ROE for a benchmark low-risk utility beyond December 31, 2013;
- a generic methodology on how to establish each utility's cost of capital in reference to the cost of capital for a benchmark low-risk utility;
- a methodology to establish a deemed capital structure and deemed cost of capital, particularly for those utilities without third-party debt; and
- for those utilities that require a deemed interest rate, if warranted, a methodology to establish a deemed interest rate AAM. If not warranted, setting a future regulatory process on how the deemed interest rate would be adjusted beyond December 31, 2013.

The BCUC has also determined that a second, subsequent phase be added to the GCOC Proceeding to determine an appropriate ROE and capital structure for all other regulated utilities in BC, once the benchmark has been established in the first phase of the GCOC Proceeding. The Corporation, in its present state, has been designated as the benchmark.

The public oral hearing for the first phase of the GCOC Proceeding occurred in December 2012. A decision on the benchmark is expected mid-year 2013. Pursuant to a BCUC order released in December 2012, effective January 1, 2013, the current ROE and capital structure for the Corporation and all other regulated entities in BC that rely on the benchmark utility to establish rates are to be maintained and made interim. The results of the GCOC Proceeding could materially impact the Corporation's earnings.

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

4. ACCOUNTS RECEIVABLE

	2012	2011
Accounts receivable – trade	**$ 77**	$ 96
Accrued unbilled revenue	**97**	114
Other	**40**	33
Allowance for doubtful accounts	**(9)**	(5)
	$ 205	$ 238

5. INVENTORIES

	2012	2011
Gas in storage	**$ 93**	$ 99
Materials and supplies	**2**	2
	$ 95	$ 101

During the year ended December 31, 2012, gas in storage inventories of $605 million (2011 - $763 million) were expensed and reported in cost of natural gas on the consolidated statements of earnings.

6. PROPERTY, PLANT AND EQUIPMENT

2012	**Weighted average depreciation rate**	**Cost**	**Accumulated depreciation**	**Net book value**
Natural gas transmission and distribution systems	**2.73%**	**$ 3,278**	**$ (949)**	**$ 2,329**
Plant, buildings and equipment	**6.15%**	**262**	**(93)**	**169**
Land	**-**	**55**	**-**	**55**
Assets under construction	**-**	**51**	**-**	**51**
		$ 3,646	**$ (1,042)**	**$ 2,604**

2011	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book value
Natural gas transmission and distribution systems	2.56%	$ 3,211	$ (880)	$ 2,331
Plant, buildings and equipment	5.04%	238	(84)	154
Land	-	55	-	55
Assets under construction	-	33	-	33
		$ 3,537	$ (964)	$ 2,573

As allowed by the BCUC, during the year ended December 31, 2012, the Corporation capitalized an allowance for debt and equity funds used during construction at approved rates of $1 million (2011 - $3 million) and $1 million (2011 - $4 million) respectively, and approved capitalized overhead of $32 million (2011 - $30 million), with offsetting inclusions in earnings.

Depreciation of property, plant and equipment for the year ended December 31, 2012 totalled $101 million (2011 - $89 million).

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

7. GOODWILL AND INTANGIBLE ASSETS

2012	**Cost**	**Accumulated depreciation**	**Net book value**
Goodwill	**$ 769**	**$ -**	**$ 769**
Intangible Assets			
Software	**105**	**(31)**	**74**
Land rights	**45**	**-**	**45**
Other	**2**	**(1)**	**1**
Assets under construction	**1**	**-**	**1**
	$ 153	**$ (32)**	**$ 121**

2011	Cost	Accumulated depreciation	Net book value
Goodwill	$ 769	$ -	$ 769
Intangible Assets			
Software	91	(22)	69
Land rights	45	-	45
Other	2	(1)	1
Assets under construction	2	-	2
	$ 140	$ (23)	$ 117

On May 17, 2007, Fortis indirectly acquired all of the issued and outstanding shares of Terasen Gas Inc. (renamed FortisBC Energy Inc.). The consideration paid for this acquisition has been recorded in the Corporation's financial statements using push-down accounting. In addition to goodwill, the Corporation has recognized additional paid-in capital related to the push-down of the excess purchase price paid by Fortis on acquisition over the fair value of the net assets acquired. There was no impairment of intangible assets and goodwill for the years ended December 31, 2012 and 2011.

During the year ended December 31, 2012, $5 million (2011 - $13 million) of fully amortized software assets were retired.

Indefinite-lived intangible assets, not subject to amortization, consist of land and certain other transmission rights and totaled $45 million as at December 31, 2012 (2011 - $45 million).

Amortization of intangible assets for the year ended December 31, 2012 totalled $15 million (2011 - $8 million), of which $1 million (2011 – nil) was amortized through regulatory assets.

Amortization of software is recorded on a straight-line basis using an average amortization rate of 12.8 per cent. Amortization of other intangible assets is recorded on a straight-line basis using an amortization rate of 2.2 per cent. Amortization rates for regulated intangible assets are approved by the BCUC, and for non-regulated intangible assets require the use of management estimates of the useful lives of assets.

The following is the estimated amortization expense for each of next five years:

2013	$ 16
2014	16
2015	17
2016	18
2017	18

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

8. REGULATORY ASSETS AND LIABILITIES

Based on the existing regulatory orders or the expectation of future regulatory orders, the Corporation has recorded the following amounts, net of income tax and amortization where applicable, which are expected to be recovered from or refunded to customers:

Regulatory assets	**2012**	2011
Regulated asset for deferred income taxes (a)	**$ 293**	$ 278
US GAAP funded status (b)	**136**	139
Energy Efficiency and Conservation program (c)	**30**	21
Deferred losses on disposal of utility capital assets (d)	**24**	15
Customer Care Enhancement (e)	**22**	11
Income taxes recoverable on post-employment benefits (f)	**18**	18
Alternative energy projects (g)	**18**	9
Pension cost variance (h)	**16**	10
Rate stabilization accounts (i)	**16**	73
Other items (j)	**16**	13
	589	587
Less: current portion of regulatory assets	**28**	73
	$ 561	$ 514

Amortization of regulatory assets for the year ended December 31, 2012 totaled $9 million (2011 - $4 million).

Regulatory liabilities	**2012**	2011
Rate stabilization accounts (i)	**$ 43**	$ 31
Regulated liability for deferred income taxes (a)	**12**	9
Negative salvage provision (k)	**6**	-
Meter reading and customer service variance (l)	**6**	-
Deferred interest mechanism (m)	**5**	8
Income tax variance (n)	**5**	12
Southern Crossing Pipeline mitigation revenues (o)	**4**	9
Other items (j)	**9**	8
	90	77
Less: current portion of regulatory liabilities	**35**	23
	$ 55	$ 54

Amortization of regulatory liabilities for the year ended December 31, 2012 totalled $3 million (2011 - $9 million).

(a) The deferred income taxes on regulated assets and regulated liabilities, and the regulated asset for deferred income taxes, is a result of ASC Topic 740, *Income Taxes* which requires the recognition of deferred income tax liabilities and assets as well as offsetting regulated assets or liabilities. There are no timing differences for tax purposes on the mark-to-market on the natural gas derivatives.

(b) The US GAAP funded status deferral account captures the difference between the carrying value otherwise determined and the funded status of the defined benefit plans and OPEBs. The regulatory asset balance represents the deferred portion of the expense relating to pensions and OPEBs that is expected to be recovered from customers in future rates as the deferred amounts are included as a component of future net benefit cost.

(c) The deferral account for the Energy Efficiency and Conservation ("EEC") program relates to costs incurred in relation to programs approved by the BCUC that provide energy efficient incentives to residential and commercial customers. The BCUC has approved the recovery of $23 million in rates over a 10 year period and the recovery of the remaining $7 million will be determined at a future period.

(d) The deferred losses on disposal of utility capital assets (property, plant and equipment and intangible assets) is a regulatory deferral account that accumulates gains and losses on the sale or removal of utility capital assets. The BCUC has approved the recovery of these costs in rates over a 20 year period.

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

8. REGULATORY ASSETS AND LIABILITIES (continued)

(e) The Customer Care Enhancement ("CCE") deferral captures all incremental costs associated with the project that were incurred prior to the project implementation date of January 1, 2012, for the purpose of permitting cost recovery, as well as costs incurred in 2012 related to the project implementation. The BCUC has approved the recovery of these costs in rates over an eight year period.

(f) The deferral account for income taxes on post-employment benefits relates to income tax amounts on post-employment benefits expense. The BCUC allows post-employment benefits to be collected from customers through rates calculated on the accrual basis, rather than a cash paid basis, which produces timing differences for income tax purposes similar to a deferred income tax asset. However, due to prior regulatory decisions this is presented as a regulatory asset. In years prior to 2009, the Corporation accounted for income taxes using the taxes payable basis of accounting, thus the tax effect of this timing difference is included in regulatory assets, and will be reduced as cash payments for post-employment benefits exceed required accruals and amounts collected from customers in rates.

(g) The alternative energy projects deferral account captures the costs and revenue associated with the investment in alternative energy solutions. The recovery of this account will be determined at a future period and is expected to be recovered from current and future alternative energy services to customers.

(h) The pension cost variance account accumulates differences between pension and OPEB expenses that are approved for recovery in rates and the actuarially determined pension and OPEB expense. Amounts are recovered in rates over a three year period.

(i) The rate stabilization accounts are comprised of the RSAM, CCRA and MCRA. The RSAM and MCRA accounts are anticipated to be refunded in rates over three years. Refund of the RSAM balance is dependent upon annually approved rates and actual gas consumption volumes. The CCRA accounts are anticipated to be fully recovered within the next fiscal year.

The mark-to-market on the natural gas derivatives included in the CCRA account is $26 million (2011 - $87 million).

	2012	2011
Current Assets		
CCRA	**$ 16**	$ 73
	16	73
Current Liabilities		
RSAM	**(9)**	(8)
MCRA	**(9)**	(6)
	(18)	(14)
Long-Term Liabilities		
MCRA	**(9)**	-
RSAM	**(16)**	(17)
	(25)	(17)
Total liabilities	**(43)**	(31)
Net rate stabilization accounts	**$ (27)**	$ 42

(j) Regulatory assets and liabilities for rate-regulated entities that have been aggregated in the tables above as other items relate to more than 65 deferral accounts, none of which exceeds $2 million individually. All of these accounts have been approved by the BCUC for recovery from or refund to customers in prior annual rate approvals or orders and are being amortized over various periods depending on the nature of the costs.

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

8. REGULATORY ASSETS AND LIABILITIES (continued)

(k) The negative salvage provision account captures the provision for costs incurred to remove assets from service either through actual removal of the asset or through disconnection from the transmission system. As actual removal costs are incurred, the negative salvage provision account is drawn down. As at December 31, 2012, removal costs of approximately $16 million were accrued as part of depreciation expense. Actual costs incurred were $14 million with the remaining amount having been previously collected from customers and transferred from property, plant and equipment. For the year ended December 31, 2011, removal costs of approximately $11 million, were recognized in operation and maintenance expenses.

(l) The meter reading and customer service variance accounts capture the differences between the expenditures that are approved for recovery in rates and actual expenditures for meter reading services and certain ongoing operating costs of the insourced activities related to the CCE project. The refund to customers of this account will be determined at a future period.

(m) The Corporation has a deferred interest mechanism which has been approved by the BCUC that requires that variances due to differences in long-term borrowings and long-term and short-term interest rates from those that have been approved in rates be returned to or recovered from customers in future rates. The balance of the deferred interest account is being amortized on a straight-line basis over three years.

(n) The income tax variance account captures the impact on tax expense due to changes in tax laws or accepted accessing practices, audit reassessments, and accounting policy changes. Amounts are refunded in rates over one year.

(o) The Southern Crossing Pipeline ("SCP") mitigation revenues deferral account relates to revenue received from third parties for the use of the SCP transportation capacity that has not been utilized by the firm transportation agreement customers and revenue received from third parties for the use of the SCP west to east transmission system. This account is used to record differences between actual revenues from SCP mitigation and what has been approved in the current revenue requirement. Amounts are being amortized over three years.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2012	2011
Accounts payable - trade	**$ 47**	$ 60
Gas derivatives	**26**	87
Gas cost payable	**69**	77
Interest payable	**25**	25
Customer deposits	**18**	19
Employee payable	**28**	26
Other	**13**	10
	$ 226	$ 304

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

10. LONG-TERM DEBT AND CAPITAL LEASE AND FINANCE OBLIGATIONS

Long-term debt		2012	2011
(a)	Purchase Money Mortgages:		
	11.80% Series A, due September 30, 2015	**$ 75**	$ 75
	10.30% Series B, due September 30, 2016	**200**	200
(b)	Debentures and Medium-Term Note Debentures:		
	6.95% Series 11, due September 21, 2029	**150**	150
	6.50% Series 18, due May 1, 2034	**150**	150
	5.90% Series 19, due February 26, 2035	**150**	150
	5.55% Series 21, due September 25, 2036	**120**	120
	6.00% Series 22, due October 2, 2037	**250**	250
	5.80% Series 23, due May 13, 2038	**250**	250
	6.55% Series 24, due February 24, 2039	**100**	100
	4.25% Series 25, due December 9, 2041	**100**	100
		$ 1,545	$ 1,545

Capital lease and finance obligations		2012	2011
(c)	Obligation under lease in lease out transactions	**$ 109**	$ 112
	Obligations under capital leases at 3.68% (2011 – 3.98%)	**14**	15
Total capital lease and finance obligations		**123**	127
Less: current portion of capital lease and finance obligations		**7**	7
		$ 116	$ 120

a) Purchase Money Mortgages:

The Series A and Series B Purchase Money Mortgages are secured equally and ratably by a first fixed and specific mortgage and charge on the Corporation's Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to $425 million.

b) Debentures and Medium-Term Note Debentures:

The Corporation's debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

The Corporation's Series B Purchase Money Mortgages, and Series 11, Series 18, Series 19, Series 21, Series 22, Series 23, Series 24 and Series 25 Medium-Term Note Debentures are redeemable in whole or in part at the option of the Corporation at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond. The Corporation's Series A Purchase Money Mortgages are not redeemable.

c) Obligation Under Lease in Lease Out Transactions:

Between 2000 and 2005 the Corporation entered into leasing arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by the Corporation from the municipalities. The natural gas distribution assets are considered to be integral equipment to real estate assets and as such these transactions have been accounted for as financing transactions. The proceeds from these transactions have been recorded as a financial liability included in capital lease and finance obligations. Lease payments less the portion considered to be interest expense decrease the financial liability. The transactions have implicit interest rates between 8.49 per cent and 9.52 per cent and are being repaid over a 35 year period. Each of the arrangements allow for the assets to be turned back over to the municipalities at the end of 17 years. If the assets are turned back to the municipalities, the expected payment would be equal to the carrying value of the obligation on the Corporation's financial statements at that point in time.

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

10. LONG-TERM DEBT AND CAPITAL LEASE AND FINANCE OBLIGATIONS (continued)

Certain of the Corporation's long-term debt obligations have issuance tests that prevent the Corporation from incurring additional long-term debt unless the interest coverage is at least two times available net earnings. In addition, the Corporation's credit agreement requires maintenance of certain financial covenants such as a maximum percentage of debt to equity. As at December 31, 2012 and 2011, the Corporation was in compliance with these covenants.

The Corporation's credit ratings and credit facility are disclosed in note 19 "Financial Risk Management – Liquidity Risk".

Required principal repayments for long-term debt and capital lease and finance obligations over the next five years and thereafter are as follows:

2013	$ 7
2014	7
2015	82
2016	207
2017	7
Thereafter	1,358
	$ 1,668

11. OTHER LONG-TERM LIABILITIES

	2012	2011
Pension and OPEB liabilities (note 13)	**$ 189**	$ 178
Ministry of Energy, Mines and Petroleum Resources funds	**3**	4
Unrecognized tax benefits (note 16)	**2**	2
Other	**-**	1
	$ 194	$ 185

The British Columbia Ministry of Energy, Mines and Petroleum Resources ("MEMPR") funds are funds the Corporation received from the MEMPR in advance of expenditures. The funds received are in support of LiveSmart BC's energy conservation and efficiency goals and are focused on the Efficiency Incentive Program for low-income households. The Corporation will use the funds to reduce the consumption of natural gas by low-income residences served by the Corporation.

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

12. SHARE CAPITAL

Authorized Share Capital

The Corporation is authorized to issue 500,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value.

Common Shares

Issued and outstanding common shares are as follows:

	2012		2011	
	Number	**Amount**	Number	Amount
Outstanding, beginning of year	**63,010,782**	**$ 719**	63,010,782	$ 719
Issued	**1,900,000**	**65**	-	-
Outstanding, end of year	**64,910,782**	**$ 784**	63,010,782	$ 719

In April 2012, the Corporation issued 1,900,000 common shares to its parent companies for total proceeds of $65 million. The issuance was a result of a higher rate base in 2012 compared to 2011 due to capital projects going into service in early 2012.

13. EMPLOYEE FUTURE BENEFITS

The Corporation is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans and supplemental unfunded arrangements. The Corporation also provides post-employment benefits other than pensions for retired employees. The following is a summary of each type of plan.

Defined Benefit Pension Plans

Retirement benefits for unionized employees under the defined benefit plans are based on employees' years of credited service and remuneration. Corporation contributions to the plan are based upon independent actuarial valuations. The most recent actuarial valuation of the defined benefit pension plans for funding purposes was at December 31, 2010 and the next required valuation is as of December 31, 2013. The expected weighted average remaining service life of employees covered by the defined benefit pension plans is 10 years (2011 – 10 years).

Effective in 2007, all employees became participants in a defined benefit pension plan in which costs are split evenly between the employees and employer. The current employees were grandfathered in their respective defined benefit plans and those plans were closed to all new members. The most recent actuarial valuation of this defined benefit pension plan for funding purposes was December 31, 2009 and the date of the next required valuation is December 31, 2012. The expected weighted average remaining service life of employees covered by this defined benefit pension plan is 11 years (2011 – 11 years).

Supplemental Plans

Certain employees are eligible to receive supplemental benefits under the defined benefit plans. The supplemental plans provide pension benefits in excess of statutory limits. The supplemental plans are unfunded and certain plans are secured by letters of credit.

Other Post-Employment Benefits

The Corporation provides certain retired employees with OPEBs that include, depending on circumstances, supplemental health, dental and life insurance coverage. Post-employment benefits are unfunded and the annual expense is recorded on an accrual basis based on independent actuarial determinations, considering among other factors, health-care cost escalation. The most recent actuarial valuation was completed as at December 31, 2010 and the next required valuation is as of December 31, 2013. The expected weighted average remaining service life of employees covered by these benefit plans is 15 years (2011 – 13 years).

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

13. EMPLOYEE FUTURE BENEFITS (continued)

The Corporation measures its projected benefit obligations and the fair value of plan assets for accounting purposes as at December 31 each year. The financial positions of the employee defined benefit pension plans and other benefit plans are presented in aggregate in the tables below:

	Defined benefit pension plans		OPEB plans	
	2012	2011	**2012**	2011
Change in fair value of plan assets				
Balance, beginning of year	**$ 289**	$ 262	**$ -**	$ -
Actual return on plan assets	**29**	20	**-**	-
Corporation contributions	**12**	12	**2**	1
Member contributions	**9**	8	**-**	-
Benefit payments	**(15)**	(13)	**(2)**	(1)
Fair value, end of year	**324**	289	**-**	-
Change in projected benefit obligation				
Balance, beginning of year	**374**	315	**93**	69
Member contributions	**9**	8	**-**	-
Current service cost	**13**	9	**3**	1
Interest costs	**16**	17	**4**	4
Benefit payments	**(15)**	(13)	**(2)**	(1)
Actuarial loss	**13**	38	**5**	20
Balance, end of year[1]	**410**	374	**103**	93
Unfunded status	**$ (86)**	$ (85)	**$ (103)**	$ (93)

[1] *The accumulated benefit obligation for defined benefit pension plans, which does not incorporate future salary level assumptions, was $361 million (2011 - $337 million).*

The net accrued benefit liability is included in note 11 "Other Long-Term Liabilities".

Included in the projected benefit obligation and fair value of the plan assets at year-end are the following amounts in respect of plans with projected benefit obligations in excess of fair value of assets:

	Defined benefit pension plans		OPEB plans	
	2012	2011	**2012**	2011
Projected benefit obligations:				
Unfunded plans	**$ 11**	$ 12	**$ 103**	$ 93
Funded plans	**399**	362	**-**	-
	410	374	**103**	93
Fair value of plan assets	**324**	289	**-**	-
Unfunded status	**$ (86)**	$ (85)	**$ (103)**	$ (93)

The projected benefit obligations for certain unfunded pension benefit plans are secured by letters of credit see note 23 "Guarantees".

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

13. EMPLOYEE FUTURE BENEFITS (continued)

The net benefit cost for the Corporation's defined benefit pension plans and OPEBs are as follows:

	Defined benefit pension plans		OPEB plans	
	2012	2011	**2012**	2011
Service costs	**$ 13**	$ 9	**$ 3**	$ 1
Interest costs	**16**	17	**4**	4
Expected return on plan assets	**(19)**	(17)	**-**	-
Amortization:				
Actuarial losses	**10**	7	**2**	2
Past service costs	**-**	-	**(2)**	(2)
Actuarial determined net benefit cost	**20**	16	**7**	5
Regulatory adjustment	**(6)**	(10)	**(2)**	-
Net benefit cost	**$ 14**	$ 6	**$ 5**	$ 5

Defined Benefit Pension Plan Assets

As at December 31, 2012 and 2011 the assets of the Corporations funded defined benefit pension plans were invested on a weighted average as follows:

	Target allocation	2012	2011
Equity	**45-55%**	**46%**	47%
Fixed income	**39-54%**	**42%**	42%
Real estate, private equity and other assets	**0-15%**	**12%**	11%
Total assets		**100%**	100%

The investment policy for defined benefit plan assets is to optimize the risk-return using a portfolio of various asset classes. The Corporation's primary investment objectives are to secure registered pension plans, and maximize investment returns in a cost effective manner while not compromising the security of the respective plans. The pension plans use quarterly rebalancing in order to achieve the target allocations while complying with the constraints of the Pension Benefits Standards Act of British Columbia and the Canada Revenue Agency. The pension plans utilize external investment managers to manage the investment policy. Assets in the plans are held in trust by independent third parties. The pension plans do not directly hold any shares of the Corporation's parent or affiliated companies.

The fair value measurements of the Corporation's defined benefit pension plan assets by fair value hierarchy level, which are described in further detail in note 18, "Fair Value Measurement" are as follows:

2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Canadian equities	**$ 45**	**$ 4**	**$ -**	**$ 49**
Fixed income	**-**	**138**	**-**	**138**
Foreign equities	**99**	**-**	**-**	**99**
Real estate, private equity and other assets	**-**	**-**	**38**	**38**
Total	**$ 144**	**$ 142**	**$ 38**	**$ 324**

2011	Level 1	Level 2	Level 3	Total
Canadian equities	$ 41	$ -	$ -	$ 41
Fixed income	-	126	-	126
Foreign equities	75	-	-	75
Real estate, private equity and other assets	-	13	34	47
Total	$ 116	$ 139	$ 34	$ 289

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

13. EMPLOYEE FUTURE BENEFITS (continued)

Defined Benefit Pension Plan Assets (continued)

The following table is a reconciliation of changes in the fair value of defined benefit pension plan assets that have been classified as Level 3:

	Real Estate
Balance as of December 31, 2011	**$ 34**
Actual return on plan assets:	
Relating to assets still held at the reporting date	**4**
Purchases, sales, and settlements	**-**
Balance as of December 31, 2012	**$ 38**

	Real Estate
Balance as of December 31, 2010	$ 27
Actual return on plan assets:	
Relating to assets still held at the reporting date	4
Purchases, sales, and settlements	3
Balance as of December 31, 2011	$ 34

There were no transfers into or out of Level 3 during the years ended December 31, 2012 and 2011.

Significant Actuarial Assumptions

The discount rate assumption used in determining pension and post-retirement benefit obligations and net benefit cost reflects the market yields, as of the measurement date, on Corporate AA bonds. The expected rate of return on plan assets assumption is reviewed annually by management, in conjunction with actuaries. The assumption is based on the expected returns for the various asset classes, weighted by the portfolio allocation.

The weighted average significant actuarial assumptions used to determine the projected benefit obligation and the net benefit cost are as follows:

	Defined benefit pension plans		**OPEB plans**	
	2012	2011	**2012**	2011
Projected benefit obligation				
Discount rate at December 31, based on Corporate AA bonds	**4.00%**	4.25%	**4.25%**	4.25%
Rate of compensation increase	**2.89%**	2.89%	**-**	-
Net benefit cost				
Discount rate at January 1, based on Corporate AA bonds	**4.25%**	5.25%	**4.25%**	5.25%
Expected rate of return on plan assets[1]	**6.62%**	6.75%	**-**	-

[1] *Developed by management with assistance from an independent actuary using a best estimate of expected returns, volatilities and correlations for each class of assets. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.*

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

13. EMPLOYEE FUTURE BENEFITS (continued)

Significant Actuarial Assumptions (continued)

The assumed health-care cost trend rates for OPEB plans are as follows:

	2012	2011
Extended health benefits		
Initial health-care cost trend rate	**8.0%**	8.0%
Annual rate of decline in trend rate	**0.5%**	0.5%
Ultimate health-care cost trend rate	**5.0%**	5.0%
Year the rate reaches the ultimate trend rate	**2018**	2017
Medical Services Plan Benefits Premium trend rate	**6.0%**	6.0%

A one percentage-point change in assumed health-care cost trend rates would have the following effects on the Corporation's OPEBs:

2012	**One percentage-point increase**	**One percentage-point decrease**
Effect on the total of the service cost and interest cost components of the net benefit cost	**$ 1**	**$ 1**
Effect on projected benefit obligation	**10**	**8**

Cash Flows

Total cash contributions for employee future benefit plans consist of:

	2012	2011
Funded plans	**$ 12**	$ 11
Beneficiaries of unfunded plans	**2**	2
Total	**$ 14**	$ 13

See note 21 "Commitments" for the 2013 contributions for the defined benefit pension plans and other benefit plans.

The following table provides the components recognized as the change in the regulatory asset during the year that would otherwise have been recognized in other comprehensive income for the years ended December 31, 2012 and 2011:

	Defined benefit pension plans		**OPEB plans**	
	2012	2011	**2012**	2011
Net actuarial losses	**$ (2)**	$ (35)	**$ (6)**	$ (20)
Amortization of past service costs	**-**	-	**(2)**	(2)
Amortization of actuarial losses	**10**	7	**3**	1
Regulatory asset	**$ 8**	$ (28)	**$ (5)**	$ (21)

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

13. EMPLOYEE FUTURE BENEFITS (continued)

Cash Flows (continued)

The following table provides the components of regulatory assets that would otherwise have been recognized in accumulated other comprehensive income and have not yet been recognized as components of net periodic benefit cost:

	Defined benefit pension benefits		**OPEB benefits**	
	2012	2011	**2012**	2011
Net actuarial loss	**$ 102**	$ 110	**$ 47**	$ 44
Past service costs	**(3)**	(3)	**(10)**	(12)
Regulatory asset, end of year	**$ 99**	$ 107	**$ 37**	$ 32

The defined benefit pension and OPEB amounts that would otherwise have been recognized in accumulated other comprehensive income of $99 million (2011 - $107 million) and $37 million (2011 - $32 million), respectively, have been deferred as a regulatory asset. See note 8 "Regulatory Assets and Liabilities".

Past service credits of nil and net actuarial losses of $10 million are expected to be amortized from regulatory assets into pension net benefit costs in 2013. Past service credits of $2 million and net actuarial losses of $3 million are expected to be amortized from regulatory assets into OPEB net benefit costs in 2013.

The following table provides the amount of benefit payments expected to be paid by the plans for each of the following years:

	Defined benefit pension benefits	**OPEB benefits**
2013	$ 15	$ 2
2014	15	3
2015	16	3
2016	16	3
2017	17	3
2018-2022	97	21

14. FINANCE CHARGES

	2012	2011
Interest on long-term debt, capital leases, and finance obligations	**$ 116**	$ 116
Interest on short-term debt	**49**	42
Interest capitalized	**(1)**	(3)
	$ 164	$ 155

15. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

Supplemental cash flow information	**2012**	2011
Interest paid in the period	**$ 163**	$ 154
Income taxes paid in the period	**9**	3

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

15. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Significant non-cash transactions		**2012**		2011
Mark-to-market of gas derivatives	**$**	**(61)**	$	(33)
Capital accruals		**2**		3
Regulatory assets and regulatory liabilities accruals		**(6)**		-
Contributions in aid of construction accruals		**7**		(4)
Regulated asset for deferred income taxes		**15**		18
Negative salvage provision transfer from property, plant and equipment to regulatory liabilities		**4**		-

Changes in non-cash working capital		**2012**		2011
Accounts receivable	**$**	**33**	$	60
Inventory		**6**		35
Accounts payable and accrued liabilities		**(78)**		(54)
Income and other taxes payable		**(6)**		4
Net regulatory assets and liabilities		**57**		42
Other		**2**		(3)
	$	**14**	$	84

16. INCOME TAXES

Provision For Income Taxes

		2012		2011
Current income taxes expense	**$**	**12**	$	17
Deferred income taxes expense		**11**		23
Regulatory adjustment		**(12)**		(24)
		(1)		(1)
Income taxes expense	**$**	**11**	$	16

Variation In Effective Income Tax Rate

Income taxes vary from the amount that would be computed by applying the Canadian federal and BC combined statutory income tax rate of 25.0 per cent (2011 – 26.5 per cent) to earnings before income taxes as shown in the following table:

		2012		2011
Combined statutory income tax rate		**25.0%**		26.5%
Statutory income tax applied to earnings before income taxes	**$**	**31**	$	33
Preference share dividends		**(12)**		(11)
Items capitalized for accounting but expensed for income tax purposes		**(4)**		(5)
Difference between capital cost allowance and amounts claimed for accounting purposes		**(4)**		(1)
Pension costs		**1**		(1)
Non-deductible expenses and non-taxable income		**(1)**		(1)
Other		**-**		2
Actual income taxes expense	**$**	**11**	$	16
Effective income tax rate		**8.94%**		12.70%

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

16. INCOME TAXES (continued)

Deferred Income Taxes

Deferred income taxes are provided for temporary differences. Deferred income tax assets and liabilities are comprised of the following:

	2012	2011
Deferred income tax liability (asset)		
Property, plant and equipment	**$ 262**	$ 265
Intangible assets	**26**	18
Regulatory assets	**42**	27
Regulatory liabilities	**(34)**	(28)
Employee future benefits	**-**	4
Share issue and debt finance charges	**-**	2
Net deferred income tax liability	**$ 296**	$ 288
Classification		
Current deferred income tax asset	**(13)**	(10)
Long-term deferred income tax liability	**309**	298
Net deferred income tax liability	**$ 296**	$ 288

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2012 and 2011:

	2012	2011
Total unrecognized tax benefits, beginning of year	**$ 2**	$ 3
Additions related to the current year	**-**	-
Reductions related to lapse of applicable statutes of limitations	**-**	(1)
Total unrecognized tax benefits, end of year	**$ 2**	$ 2

If the total amount of unrecognized tax benefits as at December 31, 2012 of $2 million (2011 - $2 million) were ultimately realized, income tax expense would decrease by approximately $1 million (2011 - $1 million) in the future. The Corporation does not expect any payments to be made for unrecognized tax benefits within the next 12 months.

Interest and penalties recognized as income tax expense related to liabilities for unrecognized tax benefits were nil for 2012 (2011 - nil). Interest and penalties accrued in the Corporation's consolidated balance sheets for unrecognized tax benefits as at December 31, 2012 were nil (December 31, 2011 - nil). Taxation years 2007 and prior are no longer subject to examination in Canada.

17. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

The Corporation hedges its exposure to fluctuations in natural gas prices through the use of derivative instruments. The Corporation's price risk management strategy aims to (i) improve the likelihood that natural gas prices remain competitive, (ii) dampen price volatility on customer rates and (iii) reduce the risk of regional price disconnects. As a result of regulatory proceedings in 2011, the Corporation has suspended all commodity hedging activity with the exception of certain elements to address the risk of regional price disconnects. The existing hedging contracts continue in effect through to their maturity and the Corporation's ability to fully recover the commodity cost of gas in customer rates remains unchanged.

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

17. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES (continued)

Volume of Derivative Activity

As at December 31, 2012, the Corporation had the following notional volumes of outstanding natural gas derivatives, designated for regulatory approval that are expected to be settled as outlined below:

	2013	**2014**
Natural gas derivatives		
Swaps and options (petajoules (*PJ*))	17	2
Gas purchase contract premiums *(PJ)*	62	12

Presentation of Derivative Instruments in the Financial Statements

In the Corporation's consolidated balance sheets, derivative instruments are presented on a net basis by counterparty where the right of offset exists.

At December 31, 2012, the Corporation's outstanding derivative balances were as follows:

2012	**Gross derivatives balance[1]**	**Netting[2]**	**Cash collateral**	**Total derivatives balance**
Natural gas commodity derivatives:				
Accounts payable and accrued liabilities	**$ 26**	**$ -**	**$ -**	**$ 26**

[1] *See note 18 for a discussion of the valuation techniques used to calculate the fair value of these instruments.*
[2] *Positions, by counterparty, are netted where the intent and legal right to offset exists.*

At December 31, 2011, the Corporation's outstanding derivative balances were as follows:

2011	Gross derivatives balance[1]	Netting[2]	Cash collateral	Total derivatives balance
Natural gas commodity derivatives:				
Accounts payable and accrued liabilities	$ 87	$ -	$ -	$ 87

[1] *See note 18 for a discussion of the valuation techniques used to calculate the fair value of these instruments.*
[2] *Positions, by counterparty, are netted where the intent and legal right to offset exists.*

The following table shows the cumulative losses at December 31, 2012 and 2011, with respect to the derivative instruments:

	2012	2011
Unrealized loss on natural gas commodity derivatives – Current portion of regulatory assets[1,2]	**$ 26**	$ 87

[1] *Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory assets rather than being recorded to the consolidated statement of earnings. These amounts exclude the impact of cash collateral postings.*
[2] *These amounts are fully passed through to customers in rates. Accordingly, net earnings were not impacted by realized amounts on these instruments.*

Cash inflows and outflows associated with the settlement of all derivative instruments are included in operating cash flows on the Corporation's consolidated statements of cash flows.

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

18. FAIR VALUE MEASUREMENT

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. A fair value hierarchy exists that prioritizes the inputs used to measure fair value. The Corporation is required to record all derivative instruments at fair value except those which would qualify for the normal purchase and normal sale exception.

The three levels of the fair value hierarchy are defined as follows:

Level 1: Fair value determined using unadjusted quoted prices in active markets.
Level 2: Fair value determined using pricing inputs that are observable.
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available.

The fair values of the Corporation's financial instruments, including derivatives, reflect a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

The natural gas derivatives are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. Any resulting gains or losses are recorded in regulatory liabilities or assets in the consolidated balance sheet. The fair value of the natural gas derivatives is calculated using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas.

The fair values of the natural gas derivatives are estimates of the amounts that the Corporation would receive or pay to terminate the outstanding contracts as at the balance sheet date. As at December 31, 2012 and 2011, none of the natural gas derivatives were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the BCUC.

The following table summarizes the fair value measurements of the Corporation's long-term debt and natural gas derivative contracts as of December 31, 2012 and 2011, all of which are Level 2 of the Corporation's financial instruments and recorded on the balance sheet at their carrying value:

	2012		2011	
	Carrying value	**Estimated fair value**	Carrying value	Estimated fair value
Long-term debt	**$ 1,545**	**$ 2,039**	$ 1,545	$ 2,026
Natural gas commodity swaps and options and gas purchase contract premium[1]	**26**	**26**	87	87

[1] *Included in accounts payable as at December 31, 2012 and 2011.*

The fair value of long-term debt is estimated using quoted market prices when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

19. FINANCIAL RISK MANAGEMENT

The Corporation is exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit Risk

Credit risk is the risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument. For cash and cash equivalents, derivative assets, accounts receivable, and other receivables due from customers, the Corporation's credit risk is limited to the carrying value on the balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk.

The Corporation is exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments, including natural gas commodity swaps and options. Because the Corporation deals with high credit-quality institutions, in accordance with established credit-approval practices, the Corporation does not expect any counterparties to fail to meet their obligations. Counterparty credit exposures are monitored by individual counterparty and by category of credit rating, and are subject to approved limits. The counterparties with which the Corporation has significant derivative transactions are A-rated entities or better. The Corporation uses netting arrangements to reduce credit risk and net settles payments with counterparties where net settlement provisions exist.

The following table summarizes the Corporation's net credit risk exposure to its counterparties, as well as credit risk exposure to counterparties accounting for greater than 10 per cent net credit exposure, as of December 31, 2012 and 2011:

	Gross credit exposure before credit collateral[1]	Credit collateral	Net credit exposure[2]	Number of counterparties >10%	Net exposure to counterparties >10%
December 31, 2012	**$ 20**	**$ -**	**$ 20**	**4**	**$ 18**
December 31, 2011	$ 88	$ -	$ 88	3	$ 51

[1] *Gross credit exposure equals mark-to-market value on physically and financially settled contracts, notes receivable, and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity.*

[2] *Net credit exposure is the gross credit exposure collateral minus credit collateral.*

In the case of commercial and industrial customers credit risk is managed by checking a corporation's creditworthiness and financial strength both before commencing and during the business relationship. For residential customers, creditworthiness is normally ascertained before commencing commodity delivery by an appropriate mix of internal and external information to determine the payment mechanism required to reduce credit risk to an acceptable level. Certain customers will only be accepted on a prepayment basis. The Corporation manages its exposure to credit risk associated with all customers by monitoring an aging of receivables and by monitoring groupings of customers according to method of payment or profile.

Liquidity Risk

Liquidity risk is the risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments. The Corporation's financial position could be adversely affected if it fails to arrange sufficient and cost effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

19. FINANCIAL RISK MANAGEMENT (continued)

Liquidity Risk (continued)

To mitigate this risk, the Corporation has a $500 million syndicated credit facility available of which $416 million was unused at December 31, 2012 (2011 - $387 million). The facility is unsecured and is used for general corporate purposes.

The Corporation targets to have, on average, sufficient liquidity to allow it not to access the capital markets for a period of 12 months. The following summary outlines the Corporation's credit facility.

	December 31, 2012	December 31, 2011
Total credit facility	**$ 500**	$ 500
Short-term notes	**(33)**	(65)
Letters of credit outstanding	**(51)**	(48)
Credit facility available	**$ 416**	$ 387

In July 2012, the Corporation entered into a one year extension of its $500 million credit facility. The extension has substantially similar terms to the facility it replaced and now matures in August 2014.

The Corporation targets a strong investment grade credit rating to maintain capital market access at reasonable interest rates. As at December 31, 2012, the Corporation's credit ratings were as follows:

Credit Ratings	**DBRS**	**Moody's**
Commercial paper	**R-1 (Low)**	**-**
Secured long-term debt	**A**	**A1**
Unsecured long-term debt	**A**	**A3**

Market Risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in foreign exchange rates or market interest rates.

Foreign Exchange Risk

Foreign exchange risk is the risk that the value of a financial instrument will fluctuate due to changes in foreign exchange rates. The Corporation's earnings are not materially exposed to changes in the US dollar-to-Canadian dollar exchange rate.

Interest Rate Risk

The Corporation is exposed to interest rate risk associated with short-term borrowings and floating rate debt. The Corporation may enter into interest rate swaps to help reduce this risk. The Corporation has existing regulatory deferrals that would absorb the impact of interest rate changes.

Natural Gas Commodity Price Risk

The Corporation is exposed to risks associated with changes in the market price of natural gas as a result of the natural gas derivatives. The Corporation's price risk management strategy covers a term of 36 months and aims to (i) improve the likelihood that natural gas prices remain competitive with electricity rates; (ii) dampen price volatility on customer rates; and (iii) reduce the risk of regional price disconnects.

In the accompanying consolidated balance sheet at December 31, 2012, the balance of $28 million (2011 - $73 million) captioned as "Current Assets: Regulatory assets" includes a $26 million (2011 - $87 million) mark-to-market adjustment representing unrealized losses on hedges that are recoverable from customers through rates.

19. FINANCIAL RISK MANAGEMENT (continued)

Market Risk (continued)

The Corporation's exposure to market risk includes forward-looking statements and represents an estimate of possible changes in fair value that would occur assuming hypothetical future movements in commodity prices. The Corporation's views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual fluctuations in interest rates or commodity prices and the timing of transactions.

20. RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent, ultimate parent and other related companies under common control. The following transactions were measured at the exchange amount unless otherwise indicated:

(a) The Corporation received $4 million in 2012 (2011 – $4 million) from FEVI, a subsidiary of FHI, for transporting gas through the Corporation's pipeline system. This revenue was included in natural gas transmission and distribution revenues on the consolidated statements of earnings.

(b) The Corporation paid nil (2011 - $49 million) during the year ended December 31, 2012 for customer care and billing services to a limited partnership in which FHI owns a 30 per cent interest. These costs were included in operation and maintenance expenses on the consolidated statements of earnings. The customer care function was in-sourced beginning 2012.

(c) The Corporation reimbursed its parent, FHI, for management services under a shared-services agreement totaling $11 million (2011 – $10 million) for the year ended December 31, 2012. The management services fee was included in operation and maintenance expenses on the consolidated statements of earnings.

(d) The Corporation charged $11 million (2011 – $9 million) to affiliated companies for management services during the year ended December 31, 2012. The management services fee was included in operation and maintenance expenses on the consolidated statements of earnings.

(e) The Corporation's ultimate parent, Fortis, grants stock options to certain employees of the Corporation under its stock option plans. For the year ended December 31, 2012, the Corporation was charged, and recorded an expense of nil (2011 - $1 million) for the fair value of the stock compensation granted by Fortis. The stock option expense was included in operation and maintenance expenses on the consolidated statements of earnings.

(f) Included in accounts receivable at December 31, 2012 was $3 million (2011 - $1 million) owed to the Corporation by affiliated companies. The amounts were unsecured and non-interest bearing.

(g) The Corporation was charged $16 million (2011 - $12 million) for the year ended December 31, 2012 by FEVI for storing gas at the Mt. Hayes LNG storage facility which became operational in April 2011. These charges were included in regulatory liabilities on the consolidated balance sheets.

(h) For the year ended December 31, 2012 the Corporation was charged $2 million (2011 - $2 million) by FortisBC Inc. ("FBC") (an indirect subsidiary of Fortis) for electricity purchases and corporate management services. For the year ended December 31, 2012, the Corporation charged $2 million (2011 - $1 million) to FBC for rent and labour charges. These charges were included in operation and maintenance expenses on the consolidated statements of earnings.

(i) Under the tax loss utilization plans, for the year ended December 31, 2012, the Corporation received $46 million (2011 - $40 million), of non-taxable dividend income on the preferred shares, and paid tax deductible interest on the debt of $46 million (2011 - $40 million) for the same period. The effect of these transactions was to transfer tax losses from FHI and were recognized on the consolidated statements of earnings.

(all tabular amounts are in millions of Canadian dollars, unless otherwise noted)

21. COMMITMENTS

The Corporation has entered into operating leases for certain building space. In addition, the Corporation has entered into gas purchase contracts that represent future purchase obligations.

The following table sets forth the Corporation's operating leases, gas purchase obligations and employee defined benefit pension plan contributions due in the years indicated:

	Operating leases	Gas purchase obligations	Employee defined benefit pension plans	Total
2013	$ 3	$ 182	$ 9	$ 194
2014	3	42	-	45
2015	3	-	-	3
2016	2	-	-	2
2017	3	-	-	3
Thereafter	8	-	-	8
	$ 22	$ 224	$ 9	$ 255

Gas purchase contract commitments are based on gas commodity indices that vary with market prices. The amounts disclosed reflect index prices that were in effect at December 31, 2012.

The Corporation sponsors defined benefit pension plans. Under the terms of these plans, the Corporation is required to provide pension funding contributions, including current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuation. If the actuarial valuation falls in the next 12 months, then the Corporation has provided for an estimate of the contributions for the upcoming year. Employee defined benefit pension plan contributions beyond the date of the next actuarial valuation cannot be accurately estimated.

In addition to the items in the table above, the Corporation has issued commitment letters to customers to provide EEC funding under the EEC program approved by the BCUC. As at December 31, 2012, the Corporation had issued $4 million of commitment letters to customers.

The Corporation and FEVI have a 35 year storage and delivery agreement related to the Mt. Hayes storage facility located on Vancouver Island. Under the agreement, the Corporation will contract for at least two-thirds of the storage capacity and deliverability provided by the storage facility. FEVI may reduce the level of storage and delivery provided to the Corporation for the last 15 years of the agreement to reflect capacity required to serve customers on FEVI's pipeline system. The Corporation expects to pay approximately $16 million in demand charges in 2013 and 2014 to FEVI for storage capacity at the Mt. Hayes storage facility.

22. CONTINGENCIES

The Corporation is subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

23. GUARANTEES

The Corporation has letters of credit outstanding at December 31, 2012 totaling $51 million (2011 - $48 million) primarily to support its unfunded supplemental pension benefit plans.

Attachment 1.0B

FILED CONFIDENTIALLY

Attachment 2.0

Separation of Terasen Inc.
and Creation of the Corporate Centre

October 31, 2003

Table of Contents

1.0 Introduction

This report sets out the plan to establish a Corporate Centre at Terasen Inc. to provide the functions that are traditionally provided by a corporate head office. The creation of the Corporate Centre will enable Terasen Gas to continue to benefit from the centralization of the highly specialized skills of employees currently providing those services at Terasen Gas. As the Terasen group of companies grows, the Corporate Centre will be able to maintain an optimal level of resources and avoid duplication of work. It also provides greater transparency in separating the operating costs of the Corporate Centre from the Terasen group of companies including Terasen Gas.

Consistent with the direction set out in the 2003 Revenue Requirements Decision, this report has three objectives:

(1) to set out the plan to transfer those Terasen Gas staff, resources and responsibilities from Terasen Gas to the Terasen Inc. Corporate Centre;

(2) to define the services to be provided and the corporate charges for those services; and

(3) to provide a business case for the provision of corporate services to Terasen Inc. by Terasen Gas.

In support of these objectives, the report indicates which assets will be transferred from Terasen Gas to the Corporate Centre and describes the service agreement between Terasen Gas and Terasen Inc. for the provision of corporate services.

The report includes a report prepared by Deloitte & Touche that presents a framework based on generally accepted methods of allocating corporate services costs to subsidiaries. This framework is used as the basis for the allocations of Corporate Centre costs.

1.1 Corporate Centre Overview

A Corporate Centre pools those services performed within organizations that can be defined as non-core activities where significant scale benefits can be achieved from conducting them centrally. Services that are typically provided through a Corporate Centre include: corporate planning and governance functions including strategic planning, internal audit, risk management; corporate financial services such as treasury, investor relations, external reporting and consolidation, and tax; and various other services including legal, insurance services, and human resource compensation and planning.

Separate Corporate Centres are generally established when companies grow sufficiently in size to include businesses operating in different markets, geographic and regulatory jurisdictions such that economies of scale can be realized through centralization. Savings are achieved by avoiding the duplication of resources that would result by replicating service provision at each business. Corporate Centres also achieve greater purchasing power when outsourcing resources by virtue of their larger size and bargaining strength. Furthermore, centralization provides access to highly skilled specialized services that would not be economic to support for a single smaller business. For a regulated utility such as Terasen Gas, these benefits flow-through to customers through lower cost of service requirements and maintaining service quality.

The benefits of scale economies must be balanced against the need for individual operating autonomy and the unique requirements of individual businesses within a corporate group. As the scale and scope of the group of companies grows, the economies of scale benefits of centralizing the provision of certain services through a Corporate Centre are enhanced. In this regard, it is important to note that the economies of scale relating to centralization have already been realized at Terasen Gas since these functions are currently centralized at Terasen Gas. Moving the services to a separate Corporate Centre will neither erode nor add to the economies of scale currently being achieved. However, over time and as the Terasen Inc. group of companies continues to grow, it is expected that additional economies will be realized which would result in a reduction in the charges from Terasen Inc.

In addition to the economy of scale benefits discussed above, Corporate Centres provide greater transparency as to the costs of running each of the businesses within the group of companies. As circumstances change in the future through continued growth across Terasen Inc., this separation will provide greater clarity to Terasen Gas and interested parties as to the services and service levels provided and the value of additional economies of scale.

1.2 2003 Revenue Requirements Application Decision

The 2003 Revenue Requirements Application of Terasen Gas Inc. (then known as “BC Gas Utility Ltd.” and in this report referred to as “Terasen Gas”) was filed in June 2002. That Application sought approval of rates for 2003 and also sought to establish a base year for the negotiation of a multi-year Performance Based Ratemaking (PBR) plan. The British Columbia Utilities Commission (“Commission” or “BCUC”) review process examined the capital and operating costs of Terasen Gas including the charges for corporate services either provided internally or by way of services provided by Terasen Inc. (then known as “BC Gas Inc.” and in this report sometimes referred to as “Inc.”).

The Commission issued its Decision on Terasen Gas’ 2003 Revenue Requirements Application (“Decision”) on February 4th, 2003. In the Decision, the Commission approved the operating and maintenance costs allowed for recovery in rates, which included a reduction to the 2003 Revenue Requirement for Terasen Gas of approximately $600,000 reflecting a reduction in the general allocation of Terasen Inc. General and Administrative costs to Terasen Gas. In addition, the Commission directed Terasen Gas to provide a plan for the separation of the pensions, salaries and expenses of Terasen Inc. staff from the Terasen Gas pensions, salaries and expenses. This would result in certain corporate services functions, which had previously been provided by Terasen Gas and cross-charged to Terasen Inc. and its subsidiaries according to the terms of the Code of Conduct and Transfer Pricing Policy, to be transferred to Terasen Inc. and then contracted back to Terasen Gas through a Corporate Services Agreement. The Decision also directed Terasen Gas to identify any services provided by Terasen Inc. to Terasen Gas, including the cost of the service and to provide a supporting business case for the contract from Terasen Inc. The establishment of a Corporate Centre at Terasen Inc. is consistent with the direction to clearly separate the Terasen Inc. staff and resources from those core to Terasen Gas.

The Decision did not make any determinations as to which specific services should be separated but indicated that it is no longer appropriate for the salaries and related costs of Terasen Inc. employees to be paid by Terasen Gas. In responding to the Decision, Terasen Gas has taken the approach that those services that relate primarily to Terasen Inc. or non-utility functions should be transferred out of Terasen Gas. Further, that any economies of scale achieved through the provision of these services at Terasen Gas should be retained when the services are transferred to Terasen Inc. and contracted back to Terasen Gas. Therefore, the total value of any services transferred from Terasen Gas to Terasen Inc. should be charged back to Terasen Gas at no more than the level of costs approved in the 2003 Revenue Requirement Decision adjusted for appropriate inflation growth and productivity. The transfer of staff and related capital and operating costs does not adversely affect the Terasen Gas cost of service since the transfer of costs to Terasen Inc. is offset by the contract back to Terasen Gas for the continued provision of those services as approved in the 2003 Revenue Requirement. By clearly defining the services currently provided in this report, Terasen Gas is assured that there will be no erosion of services or service levels provided through the Corporate Centre. This approach ensures that in complying with the direction to establish a separate Corporate Centre, there will be no adverse impact on Terasen Gas or its customers.

2.0 Background

In the past, most employees that provided services to Terasen Inc. were employees of Terasen Gas. As Terasen Inc. grew and the activities of its non-regulated and petroleum transportation businesses increased, more Terasen Gas personnel time and resources were spent supporting these activities. In 1993, the Commission approved the creation of a holding company and established a Code of Conduct and a Transfer Pricing Policy for the provision of Terasen Gas resources and services to Terasen Inc. and other businesses. In accordance with these policies, time spent by Terasen Gas employees working on Terasen Inc. and other businesses was charged directly to these subsidiaries. These policies ensured that Terasen Gas customers benefited through the sharing of economies of scale associated with cross charges recovered from those companies for the provision of corporate services. Terasen Gas and the other businesses also benefited as costs and skills expertise were shared amongst them in an efficient manner. The revenues recovered from cross charges to non-Terasen Gas businesses reduced the operating and maintenance costs and revenue requirement of Terasen Gas.

Although some portion of Terasen Gas personnel's time was effectively being outsourced to the holding company and its subsidiaries, these employees continued to provide service to Terasen Gas and as such were first and foremost considered Terasen Gas employees.

When time was spent directly on Terasen Inc. or non-Terasen Gas business, time was directly charged to them. Employees also spent time on activities which benefited both Terasen Gas and Inc. and its subsidiaries and charged this time to the Inc. General & Administrative account. This time was then allocated between Inc. and Terasen Gas using a formula based on the arithmetical average of revenues, earnings and assets. During 1993 to 2000, 80% of this time was allocated back to Terasen Gas. This allocation was reduced to 70% in 2002 and subsequently to 50% in 2003, as directed by the Commission in the 2003 Decision.

As Terasen Inc. has continued to grow and expand its non-Terasen Gas businesses, the time charged for work performed by Terasen Gas employees for Terasen Inc. and the other businesses has increased. This growth has made it increasingly important to increase the transparency and separation of Terasen Inc. and Terasen Gas functions while still retaining the economies of scale that had been achieved through centralization. In 2001, all personnel that were substantially dedicated to Terasen Gas were moved to the Surrey Operations Centre. Employees who performed shared services work for both Terasen Gas and Terasen Inc. and its subsidiaries remained at the downtown office. The functions that stayed at the 1111 West Georgia location were: Office of the CEO, Office of the CFO, Corporate Controller and External Reporting, Treasury, Tax, Financial Planning, Legal, Corporate Secretary, Enterprise Risk Management, Planning & Development, Human Resources, Public and Government Affairs and Internal Audit.

With the subsequent acquisitions of Centra Gas BC and Centra Whistler, the completion of Corridor Pipeline and the acquisition of a share of the Express pipeline system, Terasen Inc. has grown to the extent that a separate centralized corporate services centre is a cost effective approach to delivering services to the operating companies and allows the benefits of scale economies to continue to be realized by Terasen Gas and its customers.

3.0 Description of Corporate Services Required

Terasen Gas has determined that the following corporate centre services are required in order to meet its operating requirements. Many of these services relate to policy, strategy and governance activities in addition to high value skills delivery in specialized areas. Some of these services such as legal services, can be directly allocated based on direct charging of time whereas some of the services such as governance and strategic planning support are more appropriately recovered via an allocation process. These services would be required if Terasen Gas existed as a separate stand-alone entity, however, by virtue of the Corporate Centre, these costs can be spread more broadly across all of the Terasen group of companies to the benefit of Terasen Gas.

The Corporate Centre Services contract includes the following services to be provided by employees of the Corporate Centre:

<u>General Governance & Oversight Services</u>

In addition to the specific services provided for below, Terasen Gas receives the benefit of the expert advice and experience of Terasen Inc. executives who spend their time working on various committees including the Executive Committee (comprised of the CEO and senior vice presidents of Terasen Inc. as well as the heads of each operating company and the General Counsel), the Risk Management Committee and the Operating Committee.

<u>Office of the CEO</u>

The role and function of the Chief Executive Officer to Terasen Gas is provided by the CEO of Terasen Inc. The CEO office provides Terasen Gas with:

(1) All Board of Director governance and liaisons to direct development and implementation of Terasen Gas' strategic, operational and capital plans;

(2) Governance assurance that controls are in place to ensure the assets of the Company are safeguarded and optimized in the best interests of shareholders, customers and other stakeholders;

(3) Alignment and communication of the vision and direction of Terasen to employees and other stakeholders and the role of Terasen Gas in that vision and direction;

(4) Executive level succession planning and development to prepare and maintain exceptional leadership; and

(5) Act as the principal spokesperson in maintaining close communication with government, shareholders, the public and the financial markets.

Office of the CFO

The role and function of the Chief Financial Officer to Terasen Gas is provided by the CFO of Terasen Inc. The CFO office provides Terasen Gas with:

(1) Policy direction and oversight of services related to key financial areas including Treasury, Investor Relations, External Reporting, Financial Planning, Taxation and Internal Audit;

(2) Develop and implement required financing plans;

(3) Oversee the understanding, communication and adherence to accounting and securities disclosures, policies and practices;

(4) Maintain key contact relationships with debt and equity investors and investment bankers; and

(5) Lead financial elements of regulatory processes.

Treasury and Cash Management

(1) Finance Terasen Gas by preparing financing plan and recommend timing of debt and equity financing;

(2) Provide derivative management advice;

(3) Maintain investment banker and debt investor relationships;

(4) Maintain treasury related controls and compliance;

(5) Cash management, and cash forecasting;

(6) Ensure availability of short-term funds;

(7) Maintain banking and money market relationships;

(8) Arrange short term credit facilities and negotiate banking service fees;

(9) Provide education and related materials from training courses and seminars attended by Treasury staff;

(10) Maintain capital structure and provide access to financing alternatives; and

(11) Provide interest rate and foreign exchange rate forecasting.

Investor Relations

(1) Equity analyst communication;

(2) Investor and Shareholder communication;

(3) Assist in preparation of quarterly information packages, as required; and,

(4) Quarterly press release coordination.

External Reporting and Consolidation

(1) Consolidation and preparation of monthly financial statements for Terasen Gas and preparation of quarterly interim reports and annual audited financial statements;

(2) Preparation of monthly reporting journal entries (consolidation, tax, accruals, etc.), analytical reviews of accounts and monthly financial review package

(3) Preparation of analysis required for prospectus and other security filing documents as requested by Treasury Department and senior management;

(4) Preparation of quarterly report to the Audit Committee;

(5) Compilation of information in response to a variety of enquiries from operations, senior management and external bodies, such as the BCUC, external auditors and government agencies;

(6) Research current and emerging accounting policies in Canada and US;

(7) Direct response to accounting authorities in both Canada and US with respect to exposure drafts;

(8) Provide accounting policy advice for such issues as consistency of presentation, alternative treatments and resolution of complicated accounting policies and ensure compliance with Generally Accepted Accounting Principles;

(9) Representation in the CGA accounting task force where matters of national accounting standards and regulated company operations are considered and assessed; and

(10) Accounting advice and assistance as required.

Corporate Financial Analysis and Capital Management

(1) Preparation and maintenance of the five year forecasting model used for strategic planning process and in the annual budgeting process

(2) Provide financial analysis support during regulatory initiatives and evaluation of projects and new initiatives; and

(3) Provide project management and /or due diligence support where required.

Taxation Services

(1) Prepare year-end and quarterly tax provisions including preparing tax calculations and working papers for current and FIT expense, preparing the necessary journal entries, assisting auditors with external audit review, preparing tax notes to the financial statements and analyzing the taxes payable/receivable account;

(2) Prepare tax returns and all tax compliance work for Terasen Gas including identification and research technical issues, filing necessary elections and agreements, requesting post filing adjustments, and reviewing assessments and interest calculations;

(3) Calculate corporate tax installments and arrange payment;

(4) Prepare tax calculations in support of rate cases and annual reports to the BCUC;

(5) Manage GST and PST, including reviewing and filing returns, identifying issues and researching technical enquiries, coordinating filing of necessary elections, responding to queries on the application of GST or PST to particular transactions, training employees on the application of GST or to revenues and disbursements and advising employees of GST changes;

(6) Manage tax implications of payroll and employee benefits including researching and advising on taxable benefits, CPP, UIC, payroll tax issues, company pension plan issues, and preparing or reviewing taxable benefits calculations;

(7) Identify research & development and prepare and file forms;

(8) Coordinate tax audits (federal income tax, LCT, GST, provincial SST, and CCT), provide auditors access to data, research and provide answers to auditor’s requests and negotiate beneficial resolution of proposed adjustments

(9) Prepare and file Notices of Objection and Appeal Letters and coordinate legal appeals with internal or external counsel;

(10) Devise and ensure adherence to tax policies;

(11) Conduct in-depth year end reviews of tax provisions and Terasen Gas tax returns;

(12) Write memos on tax issues and tax law changes;

(13) Interpret impact of industry issues on tax;

(14) Participate in industry group tax committees such as Canadian Gas Association and make joint submissions to government bodies on issues relevant to the industry; and

(15) Provide an overall tax leadership – plan research, provide training, file advance ruling application, co-ordinate Provincial and Federal tax.

Internal Audit

(1) Develop, plan and conduct audits/reviews of areas or processes of particular interest or of identified risk and prepare internal audit reports;

(2) Conduct annual risks assessment process in conjunction with the Enterprise Risk Management group;

(3) Monitor and evaluate the effectiveness and efficiency of controls throughout the year and summarize results to the Audit Committee of the Board of Directors;

(4) Ensure that the Terasen Gas Code of Conduct compliance management is effective by conducting annual compliance reviews and acting as a resource when issues arise with respect to the Code of Conduct;

(5) Provide annual reports summarizing Internal Audit activities and findings to the BCUC as well as other reports of regulatory compliance

(6) Conduct post implementation reviews of major capital projects and acquisitions and report results to the Audit Committee;

(7) Provide assistance to the external auditors in completing their external financial audits;

(8) Coordinate activities of various internal and external assurance providers to ensure proper coverage and minimize duplication of efforts; and

(9) Undertake work at the request of the BC Utilities Commission regarding the activities and operations of Terasen Gas.

Risk Management and Insurance Services

(1) Ensure compliance with the TSX requirements on risk management by ensuring that the Board of Directors understand the principal risks of all aspects of the business in which Terasen Gas is engaged in and ensuring that there are systems in place which effectively manage and monitor those risks with a view to the long term viability of the Terasen Gas;

(2) Arrange for coverage based on assessed potential risk of damage or loss in asset values, disruptions in operations or potential legal liabilities;

(3) Advise dollar value of coverage required, most appropriate coverage and proper services required;

(4) Provide a single insurance program to achieve economies of scales and cost reductions;

(5) Work with broker in negotiating renewals and adequacy of coverage;

(6) Ensure competitive terms and consider all available options;

(7) Establish procedures and provide assistance and guidance in the reporting, handling, compiling, negotiating and settlement of claims;

(8) Provide mechanism for appropriate and timely local resolution of third party damage claims below a given threshold, and payment of same;

(9) Conduct review of contractual agreements to protect Terasen Gas from unnecessary assumption of risks;

(10) Coordinate Risk Management's group participating in industry associations and education seminars;

(11) Establish loss control standards to help ensure consistent and high degree of loss; prevention in all operating units and minimize impact when they do occur;

(12) Ensure familiarity with policies and wordings;

(13) Encourage and establish procedures for loss control;

(14) Administer Certificates of Insurance;

(15) Preparation of management reports;

(16) Provide additional insurance for individual construction projects, as required; and

(17) Provide bonding as required.

Strategic Planning & Development

(1) Coordinate the annual update of the Corporate and Business Unit Strategic plan including Terasen Gas;

(2) Monitor the industry and business trends that influence Terasen Gas;

(3) Provide support to any major initiative which requires senior project management skills (for example, future Lease In Lease Out (LILO) transactions; and

(4) Organize management and Board strategy sessions that involve Terasen Gas.

Corporate Secretary's Office

(1) Ensure all governance activities required by external regulators and third parties are appropriately carried out, including Securities filings; and

(2) Manage the relationship with the Board of Directors, with specific accountability for the Corporate Governance Committee of the Board.

Legal Department

(1) Provide all legal services to Terasen Gas;

(2) Direct the provision and management of outside legal services to Terasen Gas;

(3) Provide management of all enterprise litigation;

(4) Provide direct, as agreed to, legal counsel on regulatory matters;

(5) Ensure legal compliance for press release, financial reports and other disclosure documents;

(6) Review, as required, legal issues that may arise including claims, actions, legal transfer, contracts, and regulatory matters; and

(7) Provide general miscellaneous legal support and advice to management.

Government Relations and Public Affairs

(1) Maintain network of contacts with elected officials and their staffs at the provincial, federal and municipal levels;

(2) Participate in industry bodies such as BC Business Council and Canadian Gas Association in determining positions to be taken on public policy issues;

(3) Provide policy advisory role on Aboriginal affairs and work on relations with Tribal Councils and Bands;

(4) Approve and review communications going to the public;

(5) Report on public opinion research;

(6) Assist in the preparation of letters to stakeholders and other communication by senior management;

(7) Oversee the development and implementation of the community investment strategy; and

(8) Oversee responses to corporate social responsibility and sustainability surveys and develop a proposal for a new sustainable development policy.

Human Resources Compensation and Planning

(1) Consult with management on the maintenance, development and governance of employee and retiree benefit programs, pension plans, employee savings plans and employee assistance programs;

(2) Provide assistance on annual wage and salary increases, providing labour market comparisons, establishing and implementing ad hoc increases for long term disability and pension recipients;

(3) Ensure that employment practices are in compliance with applicable regulations and legislation through development and administration of appropriate corporate policies and procedures;

(4) Consulting and direction on disability management guidelines and policy;

(5) Oversee the annual preparation of the executive succession plan and present the plan to the Management Resources Committee and to the Board of Directors;

(6) Corporate governance and direction regarding benefits carriers, benefits and pension consultants, financial services providers;

(7) Corporate reporting to legislative bodies, CCRA, Statistics Canada, Pension Standards, as required;

(8) Corporate direction and governance on policy development and maintenance;

(9) Provide support, training and development of staff on Corporate initiatives, systems, and policy;

(10) Provide support on Labour and Employee relations issues;

(11) Corporate governance of salary and benefits administration, including executive and management compensation; and

(12) Ensure that effective management practices are in place.

4.0 Separation of Terasen Inc.

This section of the report sets out the resources and assets currently included in the Terasen Gas cost of structure that will be transferred to the Corporate Centre by separating the Terasen Inc. functions from Terasen Gas.

4.1 Transfer of Employees, Salaries, Pensions and Expenses

With the creation of the Corporate Centre, the 47 employees on the Terasen Gas payroll who perform the head office functions noted above, and their related costs will be transferred from Terasen Gas to Terasen Inc. There will be 36 employees located at the downtown Vancouver head office location and 11 employees at the Surrey Operations Centre. The amount of salaries, pension and other expenses that previously remained and were recorded in Terasen Gas will now be incurred by Terasen Inc. The total amount of these expenses is $ 8,270,000 as set out below. With the transfer of the 47 employees to the Terasen Inc. payroll, Terasen Gas' direct labour and other expenses will be reduced by $7,321,000 and facilities and IT costs will be further reduced by $950,000 which will be recovered from Terasen Inc. Terasen Gas will then incur a corporate service charge from Terasen Inc. for the professional and management services to be provided by the Corporate Centre to Terasen Gas.

Total annual labour costs for the 47 employees (comprised mainly of professional staff), which include salaries and all benefits other than pensions and other post employment benefits ("OPEBs") being transferred from Terasen Gas amounts to $4,385,000. The pension expense and other post employment benefits related to these 47 employees has been calculated at $725,000 with the assistance of Towers Perrin for the defined benefit plans and the Terasen pension administrator for the defined contribution plans. This amount does not include the bonus portion of the pension expense which was not included in Terasen Gas' cost of service. The pension expense related to executive bonuses will be incurred by Terasen Inc. and not allocated to Terasen Gas. Other Expenses of $2,211,000 is comprised mostly of allocated shareholder expenses and allocated directors' compensation totaling $656,000 and consulting and contractor fees mainly for benefits, compensation and labour relations consultants, accounting and taxation consultants, and external legal counsel totaling $890,000. Employee expenses, other administrative expenses, overhead recoveries and the labour costs for 5 Terasen Gas union employees who will be 100% contracted to Terasen Inc. to perform external reporting, taxation and claims management services make up the remaining balance. The labour charge for the 5 Terasen Gas employees noted above is charged to Inc. in accordance with the Transfer Pricing Policy.

Terasen Inc. has contracted Terasen Gas to manage Terasen Inc.'s facilities and Information Technology infrastructure. Terasen Gas will charge Terasen Inc. $471,000 for the rent for the 24th floor of 1111 West Georgia, $264,000 for Information Technology maintenance expenses, and $108,000 for the cost of software licenses related to Terasen Inc. employees. Further, Terasen Gas will charge Terasen Inc. an additional $107,000 per annum for the use of space in the Surrey Operations Centre for eleven workstations used by the eleven Terasen Inc. employees noted above and an additional three workstations in Surrey utilized by the Corporate Centre employees. In an effort to contain costs, improve service levels to Terasen Gas and limit the space required at 1111 West Georgia, the employees from the Internal Audit, Enterprise Risk Management and Human Resources Benefits group will be located at the Surrey Operations Centre. The total Facilities and IT recoveries by Terasen Gas from Inc. will amount to $950,000.

The total transfer of budgeted direct O&M costs in Terasen Gas in 2004 is summarized as follows:

Salaries and benefits	$	4,385,000
Pensions and OPEBs		725,000
Other expenses		2,211,000
	$	7,321,000
Facilities and IT recoveries/charges		950,000
	$	8,270,000

4.2 Transfer of Assets

Assets associated with the Corporate Centre will be transferred to Terasen Inc. at their net book value which is estimated to be equivalent to fair market value. These assets are comprised mainly of leasehold improvements, computer hardware, computer software, office furniture, office equipment, and communications equipment. The net book value of these assets calculated at December 31, 2003 is estimated to be $1,465,000. A detailed listing of assets transferred is included in Attachment A to this report.

Transferring the assets to Terasen Inc. at net book value will result in a reduction in rate base. The impact on the revenue requirement is calculated as follows:

Reduction in depreciation expense	$ (305,000)
Increase in tax expense (loss of CCA)	144,000
Return on asset	(138,000)
Net impact in revenue requirement	$ (299,000)

4.3 Transfer of Liabilities

Liabilities related to the Corporate Centre employees to be transferred such as pensions, other post employment benefits and accrued vacation will also be transferred to Terasen Inc. The net pension and OPEB liability for these employees have been estimated to be $212,000 as per the Towers Perrin report calculations. The total vacation accrual for these employees is currently estimated at $323,000. These amounts will be adjusted to reflect the actual amount of the liability at December 31st, 2003 when they are transferred from Terasen Gas to Terasen Inc.

4.4 Impact of Separating Terasen Inc.

In summary, the separation of Inc. results in the following:

(a) 47 employees from the Terasen Gas payroll will be transferred to Terasen Inc.

(b) Total expenses related to these employees and their areas of service, including pensions and other post employment benefits total $7,321,000 which will be transferred to Terasen Inc.

(c) Total facilities and IT recoveries to be charged to Terasen Inc. total $950,000.

(d) Assets transferred to Terasen Inc. are estimated to be $1,465,000, and will be reflected as a reduction in rate base. The effect of the transfer of assets on the revenue requirement is $299,000.

(e) Liabilities associated with the 47 employees will also be transferred to Terasen Inc. This is estimated to be $207,000 for pensions and OPEBs and $323,000 for accrued vacation.

(f) The total amount of revenue requirement associated with the resources and assets in the separation of Terasen Inc. from Terasen Gas prior to the corporate services charge is calculated to be $8,570,000 as shown in the summary table below:

Transfer of 47 employees expenses and related costs	$ 7,321,000
Facilities and IT recoveries	950,000
Transfer of assets	299,000
	$ 8,570,000

5.0 Cost Allocation Study of Corporate Centre Costs

In order to ensure the reasonableness of the allocation of Corporate Centre costs to Terasen Gas, a cost allocation study was undertaken.

Deloitte & Touche LLP were engaged to assist in developing an approach to allocate shared corporate services costs from Terasen Inc. to its regulated and non-regulated subsidiaries. A copy of this report is attached in Attachment B. Based on the recommendations in that report, a combination of methods was utilized to determine the allocation of the shared corporate service costs to Terasen Gas. These are summarized as follows:

(1) Direct costs represent specific time and services provided by individuals to support activities of Terasen Gas. Employees will charge specific time to charge orders of Terasen Gas. Accordingly, time sheet specific direct allocations will account for a significant amount of the budgeted charges to Terasen Gas.

(2) Indirect costs which cannot be directly attributable will be allocated using the formula approach based upon the Massachusetts formula as discussed in the Deloitte & Touche report.

(3) Corporate sustaining costs which refer to activities undertaken to support the organization as a whole and benefit all the business units will also be allocated using the Massachusetts formula approach.

(4) Costs that do not impact Terasen Gas, such as time and resources spent on major projects such as acquisitions, or on non-Terasen Gas business, will be fully and directly allocated to Terasen Inc. or one of its subsidiaries. This includes the bonus component of the pension expense which is fully allocated to Terasen Inc.

The formula approach refers to the method of charging indirect and corporate sustaining costs to a common pool and then allocating them to the subsidiaries using a mathematical formula. The Massachusetts Formula is in extensive use in industry and is composed of the arithmetical average of (1) operating revenue, (2) payroll, and (3) average net book value of tangible capital assets plus inventories. The use of these factors represents the total activity of all business segments as a means to allocate costs that cannot be directly assigned. The Commission's Decision allowed a maximum of 50% of common costs to be allocated to Terasen Gas. Using the Massachusetts Formula, Terasen Gas would be allocated 53% of the common costs of the Corporate Centre. The Nebraska formula method was also considered, but this formula only utilized two of the above parameters (it excludes operating revenue) and its use would have resulted in a slightly greater charge to Terasen Gas as it calculates a 54.1% allocation to Terasen Gas.

The table below shows a summary of the results based on 2004 estimates:

			Terasen Gas		Inc. and subs		Total
A	Operating Revenues	$	500,000	$	480,122	$	980,122
			51.0%		49.0%		100.0%
B	Payroll	$	66,226	$	64,048	$	130,274
			50.8%		49.2%		100.0%
C	Avg. NBV of tangible capital assets + inventories	$	2,400,000	$	1,788,564	$	4,188,564
			57.3%		42.7%		100.0%
	Massachussets Method - avg of A,B,C						
A	Operating Revenues		51.0%		49.0%		100.0%
B	Payroll		50.8%		49.2%		100.0%
C	Avg. NBV of tangible capital assets + inventories		57.3%		42.7%		100.0%
			53.0%		**47.0%**		**100.0%**
	Kansas/Nebraska Formula - avg of B,C						
B	Payroll		50.8%		49.2%		100.0%
C	Avg. NBV of tangible capital assets + inventories		57.3%		42.7%		100.0%
			54.1%		**45.9%**		**100.0%**

Using both the direct and formula based cost allocation methodologies, Terasen Gas would be charged $9,158,000 for the services to be provided by the Corporate Centre group. This is comprised of two components: $5,820,000 of direct charges for labour and overheads for work performed directly on Terasen Gas and an allocated amount of $3,338,000 as its share of the common costs incurred by Terasen Inc. based on the Massachusetts formula. This amounts to 52.1% of the total Corporate Centre costs.

However, as previously stated during the current PBR settlement, Terasen Gas' cost of service will not be increased due to establishment of a Corporate Centre. The current amount embedded in Terasen Gas' cost of service for all the corporate centre services is $8,570,000 as noted in Section 4.4. Therefore, the management fee for the professional services provided by Terasen Inc. to Terasen Gas will be set at $8,570,000 which represents the amount currently included in the Terasen Gas cost of service for these services. This results in an allocation of 48.8% of the total Corporate Centre costs to Terasen Gas.

The table below summarizes our results:

	Results from Allocation Study		Proposed Management Fee	
	Charges to Terasen Gas	% of Inc total charges	Charges to Terasen Gas	% of Inc total charges
Direct Charges	$ 5,820	51.6%	$ 5,446	48.3%
Common Costs	3,339	53.0%	3,124	49.6%
Total Charges	$ 9,158	52.1%	$ 8,570	48.8%

6.0 The Corporate Services Fee

Based on the cost allocation study which uses a combination of direct charges and formula based allocation of common costs, the corporate services fee from Terasen Inc. to Terasen Gas would be set at $9,158,000. However, as noted in Section 1.2 of the report, the total charge for services transferred from Terasen Gas to Terasen Inc. will be charged back at the same level of costs as approved in the 2003 Revenue Requirements Decision, adjusted for inflation, growth and productivity in accordance with the PBR model. For 2004, this amount was determined to be $8,570,000 as noted in Section 4.4. Accordingly, the amount to be charged to Terasen Gas in 2004 for the corporate services provided is $8,570,000.

7.0 Corporate Centre Services - Business Case

This section of the report addresses the requirements expressed in the Decision at page 52 that "BC Gas Utility is to identify any services that it has contracted for from BC Gas Inc. in the next revenue requirements filing and should include information on the cost of service and business case supporting the contract." The alternative means available to provide such services through in-sourcing at Terasen Gas or by contracting such services externally are discussed below. The comparison establishes the business case to Terasen Gas for the provision of services from Terasen Inc. relative to Terasen Gas' other alternatives.

In order to assess the value of the Corporate Services arrangement to Terasen Gas, the corporate services fee was compared to an estimate of the cost of in-sourcing the activities within Terasen Gas or outsourcing them to third parties. Because many of the services relate to governance, policy or strategy and reflect the economies of scale from a corporate centre approach, it is more reasonable to look at the in-sourcing alternative (or replication of such services on a stand alone basis) rather than outsourcing even where estimates of market costs for resources of a similar level (i.e. from professional services providers) can be obtained.

The focus of this analysis was on whether the bundle of services, contained in the proposed Corporate Services contract, is cost effective for Terasen Gas and its customers. The cost of the stand-alone alternative was built up in stages beginning with labour requirements. Each service was reviewed for the required incremental staffing complement needed to meet the service demand. For some services it was possible to reduce the level of professional expertise as a way of minimizing labour costs and substitute contract services from professional services providers. However, insourcing would result in the loss of scale economies.

The total number of Corporate Centre related employees amounts to 52 full time equivalents (FTEs). In determining the directly attributable costs time sheet estimates were utilized and based on the 2003 planned chargeable hours relating to Terasen Gas by individual. A total 32.9 FTEs were included in these estimates. A review of the number of employees that would be required to replicate the services of the Corporate Centre within Terasen Gas was completed on a functional area basis.

The direct costs associated with employees required on a stand alone basis were estimated based on the existing compensation and benefits levels of the incumbents in these roles. Standard estimates were made for personnel supporting costs such as IT, telecom, facilities, fees and dues, office supplies, employee expenses, pensions and OPEB costs, etc. These costs would be expected to be very similar to those incurred in the corporate centre on a per employee basis.

Consulting and contractor costs were also estimated on a stand alone basis and would be generally consistent with costs incurred by the Corporate Centre except to the extent that some groups (e.g. Taxation) would be expected to contract for certain expertise rather than in-source it whereas the corporate centre would actually have a resource on staff.

A summary of the review conducted by functional area is provided below.

CEO

The Chief Executive Officer's functions are currently not performed within Terasen Gas by the President which fulfills the role of a chief operating officer which is a full time role. Historically, when the Terasen group of companies was smaller, the utility executive group was larger with a combined President/CEO role and a Senior Vice President of Operations who in turn had a number of operating vice presidents reporting to him. As the size of the corporate group expanded, Terasen Gas streamlined its executive and the duties of the President/CEO and Senior VP of Operations position were redistributed resulting in the current structure and division of responsibilities.

If the duties of the chief executive were moved back into Terasen Gas on a stand alone basis, the President would be unable to absorb them. It is unlikely that two separate positions for CEO and President would be maintained, but an additional senior executive position would be required in order to reabsorb and redistribute the responsibilities performed respectively by the CEO, the CFO and the Terasen Gas President roles in the current organization structure (see further discussion under CFO below). This would likely result in expanding the President's current responsibilities.

The requirement to take on greater responsibility in a stand alone Terasen Gas by the President/CEO would result in off loading of responsibilities onto a newly created senior executive position and the existing Terasen Gas executive. The CEO's area currently includes 3 FTEs including the CEO and two support staff of which the directly attributable time amounts to 1.4 FTEs (0.3 of which relates to the CEO). It was estimated that Terasen Gas would require approximately one FTE of time associated with the additional support staff relating to the expanded executive duties. The analysis also took into consideration that compensation adjustments and costs associated with an additional executive resource would be required under the stand alone structure

CFO & External Reporting

The corporate centre will have six FTEs providing services to the Terasen Group of companies of which 3.3 FTEs can be directly attributed to Terasen Gas' requirements. It is estimated that on a stand alone basis one manager and two accounting analysts would be required. The duties performed by the current CFO on behalf of Terasen Gas would still be required on a stand alone basis and could not be absorbed by the VP Finance & Regulatory Affairs. While this would not be expected to result in the addition of another VP level role, it would necessitate a restructuring of the existing position and responsibilities and result in the requirement for one additional senior resource beyond that in the existing structure.

Corporate Communications and Government Affairs

The corporate centre will have two staff of which 1.3 FTEs can be directly attributed to Terasen Gas. It is estimated that on a stand alone basis two employees would be required. Consulting costs would be similar to those currently allocated.

Corporate Secretary

This group consists of 3 individuals including the General Counsel. The majority of their time is attributable to the utility or 2.4 FTEs. However corporate centre provides significant economies of scale in this area as the costs of the board, shareholder, annual report and auditing expenses are allocated from this area. On a stand alone basis, Terasen Gas would have to bare virtually all these cost versus sharing them amongst the Terasen group of companies.

Risk Management and Insurance Services

This group includes four employees, all of whom would have to be replicated within the utility on a stand alone basis or certain expertise contracted in at a higher cost. Currently only 2.2 FTEs are directly attributable to Terasen Gas.

Corporate Financial Analysis and Capital Management

This group includes two senior financial analysts and a director of which approximately 1.6 FTEs are attributable to Terasen Gas requirements. On a stand alone basis it is estimated that Terasen Gas would have to replace two of these individuals to continue to meet Terasen Gas' needs.

Internal Audit

The internal audit group is resourced with six staff including a director of internal audit, four internal auditors and an administrative assistant for the group. Approximately 4.1 FTEs are attributable to Terasen Gas related audit services. Although some of the skill sets are transferable, it would not be shared with the finance group in order to maintain their independence. It is estimated that Terasen Gas would need 5 employees in a stand alone internal audit group.

Human Resources

The corporate group consists of seven individuals to manage pension, benefit and compensation programs of which 5.2 FTEs are directly attributable to the requirements of the utility. Due to the size of the organization and the requirements of the collective bargaining related processes it is estimated that six full time employees would be required in the utility on a stand alone basis including a senior executive position. The stand alone costs include consulting/contractor related costs that are consistent with those costs incurred on behalf of the utility in the corporate centre group.

Legal

The corporate group has seven staff including four lawyers and 3 legal secretaries. The majority of the time spent by the group is directly attributable to the requirements of the utility (5.8 FTEs). In addition, external legal support would continue to be required by Terasen Gas for specialized services. It is estimated that Terasen Gas would reduce the current staff levels and only require to 3 lawyers and two support staff on a stand alone basis supplemented by additional contracted legal services for more complex requirements

Strategic Planning and Development

This group consists of 3 employees including a senior executive, a senior financial professional and an administrative assistant. Currently approximately 0.8 FTEs is directly attributable to utility requirements. On a stand alone basis it is estimated that one employee would be required in the utility to provide these services supplemented by external consulting support.

Taxation

The corporate centre has 5 FTEs including four tax professionals with increasing levels of expertise as well as an administrative assistant. Currently approximately 3.0 FTEs of time are attributable to Terasen as requirements. On a stand alone basis Terasen Gas would still require 3 staff supplemented with expert tax advice from a professional services firm.

Treasury and Cash Management

The treasury group consists of 3 individuals, the assistant treasurer and two analysts of which approximately 2.0 FTEs is attributable to utility requirements. On a stand alone basis it is estimated that two employees could satisfy the requirements. Contract and consulting costs would be consistent with those currently shared amongst the group of companies.

As indicated above, while staff related costs could be expected to be consistent with those incurred in the Corporate Centre, the total number of FTEs Terasen Gas would require is greater than the number provided through the Corporate Centre in most areas. This is driven by the requirement to hire full time positions as opposed to utilizing a shared resource. This represents an increase of more than 6 FTEs net to replicate corporate services on a stand-alone basis. In addition, certain skill requirements would have to be supplemented with contracted services from professional services firms.

It is estimated that the cost to replicate the Corporate Centre services within Terasen Gas is approximately $9,500,000 on an annual basis. This cost estimate does not consider the start-up costs required to establish a stand-alone alternative, such as recruitment costs and learning curve considerations, or the incremental contract management resources needed to manage corporate services that would be outsourced to third parties.

In addition, Terasen Gas currently benefits from economies of scale resulting from participating in joint insurance and employee benefit programs as part of a corporate group. The cost of these programs would be greater if these were to be sourced for Terasen Gas on a stand alone basis rather than as corporate programs under a Terasen Inc. umbrella because fixed administrative costs would not be shared over as large a number of employees and risk diversification/buying power would not be as great driving higher insurance related costs. A more detailed assessment would be required to quantify these additional cost impacts but they would be additive to the already more costly stand alone alternative.

Based on the discussion above, the $9,500,000 cost estimate for the stand-alone alternative is approximately $900,000 or 11% higher than the planned Corporate Service fee from Terasen Inc. for a similar suite of services. Since the planned management fee is well below both the estimated cost of the stand alone alternative and the amount that would be determined utilizing direct costing and the industry accepted allocation methods (Massachusetts and Nebraska methods), Terasen Gas believes it represents good value to the Terasen Gas and its customers. Moreover, because the planned fee is consistent with the cost of service built into rates for these activities and limited future increases based on the PBR formula, the fee incorporates productivity benefits.

8.0 Corporate Services Agreement

Terasen Gas will enter into an annual Corporate Centre Services agreement with Terasen Inc. for the services it requires and will receive from Terasen Inc. The services will be paid for through an annual corporate services fee. The contract will be effective January 1, 2004.

The Corporate Services Agreement (CSA) will describe the services relating to the provision of management and professional services to be provided by Terasen Inc. to Terasen Gas as set out in this report.

To satisfy the dual objectives of simplicity and fairness, the contract will represent a maximum charge that is consistent with the following:

(1) The total charge for 2004 will be $8,570,000, which is the amount actually incurred in 2003 adjusted for inflation, growth and productivity per the PBR formula. This ensures that the Terasen Gas revenue requirement remains unchanged through the separation of these functions..

(2) The contract is of take or pay nature. This is consistent with the treatment of the current and ongoing Continuing Services contracts between Terasen Gas and its affiliates. These contracts cover services provided by Terasen Gas employees to the non-regulated affiliated companies. However, it caps the level of cost for the prescribed service under the CSA in the event that the actual time spent exceeds the estimates used in the underlying costing assumptions. This differs from the continuing services contracts, where Terasen Gas recovers the costs of incremental service delivery beyond that contracted for. The fixed fee arrangement is of value to Terasen Gas in that it provides certainty of cost effective corporate services while providing protection to the provider of such services since Terasen Inc. must maintain personnel and incur the related cost to meet the contracted level of service.

(3) The charges must be in accordance with the services agreed to in the contract. Any services not previously contemplated should be provided in a separate supplement to the agreement.

(4) If any services are not provided by Inc. in accordance with the agreement, then appropriate credit should be given to Terasen Gas for such deficiency of services based upon a reasonable estimate of allocated cost.

The pricing terms of the Corporate Services Agreement are based on an annual corporate services fee. The fee is subject to review each year and subject to adjustments following the PBR formula.

The term of the agreement is for one year, subject to annual renewals. The annual corporate services fee will be subject to renegotiation for any change in services. To allow for increases or decreases in associated staffing levels, notification for termination of or changes to the contract or service requirements must be given with six months' written notice.

9.0 Continuing Services

Terasen Gas will continue to provide certain support services to Terasen Inc. in accordance with the Code of Conduct and Transfer Pricing Policy. Services to be provided by Terasen Gas include payroll processing, facilities management, information technology and enterprise resource planning, web site administration, mailroom support, and accounts payable. Total charges to be recovered by Terasen Gas from Terasen Inc. for 2004 are estimated at $300,000.

Terasen Gas will also charge Terasen Inc. for the 5 union employees that will be fully contracted out to Terasen Inc. in accordance with the Transfer Pricing Policy.

10.0 Summary

This report sets out a plan for separating Terasen Inc. resources and responsibilities from Terasen Gas by establishing a Corporate Centre for the provision of specified corporate services to Terasen Gas and other Terasen Inc. subsidiaries. The Corporate Centre maintains the economies of scale presently being achieved through the centralization of these services at Terasen Gas and provides greater transparency in separating the operating costs of the Corporate Centre from the Terasen group of companies including Terasen Gas.

The report indicates which assets and resources will be transferred from Terasen Gas to the Corporate Centre as well as certain services that will continue to be provided to Terasen Inc. by Terasen Gas. In addition, the report details the specific corporate services to be provided from the Corporate Centre to Terasen Gas by functional area.

The proposed Corporate Services fee that will be specified in the Corporate Services agreement will be neutral in terms of revenue requirements impact based on the allowed cost of service resulting from the 2003 Revenue Requirement proceeding and as adjusted according to the PBR formula. For 2004, this amount has been determined to be $8,570,000.

An allocation of corporate centre costs among the various subsidiaries based on generally accepted costing methodologies is presented in the report. This allocation indicates that $9,158,000 of costs can be attributed to Terasen Gas. This analysis supports a Corporate Services fee higher than the $8,570,000 fee recommended in the report and as reflected in the current costs allowed in the Terasen Gas revenue requirement. This reinforces the reasonableness of the existing allocation from a Terasen Gas perspective. In order to further validate the Corporate Services fee, a business case comparison was performed comparing the Corporate Services fee to the cost of replicating these services on a stand-alone basis. This analysis shows that the cost would be $9,500,000 if Terasen Gas were to provide these services on a stand-alone basis. This also supports the conclusion that the Corporate Services fee is reasonable and provides value to Terasen Gas and its customers.

The Corporate Centre and the associated Corporate Services agreements will be put in place January 1, 2004.

Attachment A

Detailed Listing of Assets Transferred

Terasen Gas Inc.
Calculation of Assets held at Head Office for Terasen Inc. at December 31, 2003

Quantity	Description	Est. Avg.Age	Estimated value per unit	Total Cost	Accum. Dep'n	NBV	Annual Dep'n
	Leasehold Improvements						
1	Leasehold improvements	0	660,100.00	660,100.00	0.00	660,100.00	72,011.00
	Computer Hardware						
26	Computers (desktop)	3	4,000.00	104,000.00	62,400.00	41,600.00	20,800.00
40	Computers (laptop)	3	5,000.00	200,000.00	120,000.00	80,000.00	40,000.00
4	Servers	3	13,500.00	54,000.00	32,400.00	21,600.00	10,800.00
			22,500.00	358,000.00	214,800.00	143,200.00	71,600.00
	Computer Software						
66	Software	3	1,000.00	66,000.00	24,750.00	41,250.00	8,250.00
	Office Furniture						
5	Executive Offices	10	25,000.00	125,000.00	62,500.00	62,500.00	6,250.00
4	Medium Offices	10	10,000.00	40,000.00	20,000.00	20,000.00	2,000.00
14	Small Offices	10	7,000.00	98,000.00	49,000.00	49,000.00	4,900.00
28	Workstations (desk, chair, file cabinet)	5	6,000.00	168,000.00	42,000.00	126,000.00	8,400.00
62	File Cabinets	5	1,400.00	86,800.00	21,700.00	65,100.00	4,340.00
1	Meeting Room -BC	10	50,000.00	50,000.00	25,000.00	25,000.00	2,500.00
1	Meeting Room - Inland	10	15,000.00	15,000.00	7,500.00	7,500.00	750.00
1	Meeting Room - Seymour	10	10,000.00	10,000.00	5,000.00	5,000.00	500.00
1	Other Meeting Rooms	10	5,000.00	5,000.00	2,500.00	2,500.00	250.00
56	Meeting Room Chairs	10	1,100.00	61,600.00	30,800.00	30,800.00	3,080.00
15	Whiteboards	5	1,500.00	22,500.00	5,625.00	16,875.00	1,125.00
1	Lunch Room	5	1,400.00	1,400.00	350.00	1,050.00	70.00
1	Reception Desk	5	20,000.00	20,000.00	5,000.00	15,000.00	1,000.00
8	Reception Area Chairs	5	3,000.00	24,000.00	6,000.00	18,000.00	1,200.00
6	Coffee tables	5	1,200.00	7,200.00	1,800.00	5,400.00	360.00
2	AV Cart	5	550.00	1,100.00	275.00	825.00	55.00
1	Mail Slots	5	300.00	300.00	75.00	225.00	15.00
			158,450.00	735,900.00	285,125.00	450,775.00	36,795.00
	Office Equipment						
25	Printer	3	4,000.00	100,000.00	15,000.00	85,000.00	5,000.00
4	Fax Machine	5	2,000.00	8,000.00	2,000.00	6,000.00	400.00
1	AV Equipment (BC Room)	5	10,000.00	10,000.00	2,500.00	7,500.00	500.00
4	Photocopier	5	15,000.00	60,000.00	15,000.00	45,000.00	3,000.00
2	Scanners	3	800.00	1,600.00	240.00	1,360.00	80.00
			31,800.00	179,600.00	34,740.00	144,860.00	8,980.00
	Communications Equipment						
55	Standard Phone	10	800.00	44,000.00	22,000.00	22,000.00	2,200.00
1	Switchboard	10	5,000.00	5,000.00	2,500.00	2,500.00	250.00
			5,800.00	49,000.00	24,500.00	24,500.00	2,450.00
	Total of Purchased Assets			**2,048,600.00**	**583,915.00**	**1,464,685.00**	**200,086.00**

Summary

Class	Description	Depn Rate	Cost	Accm Depn	NBV	Annual Dep'n
48230	Leased Premises BC Gas Centre	10.00%	660,100.00	0.00	660,100.00	72,011.00
48310	Computer Hardware	20.00%	358,000.00	(214,800.00)	143,200.00	71,600.00
48320	Computer Software	12.50%	66,000.00	(24,750.00)	41,250.00	8,250.00
48330	Office Equipment	5.00%	179,600.00	(34,740.00)	144,860.00	8,980.00
48340	Office Furniture	5.00%	735,900.00	(285,125.00)	450,775.00	36,795.00
48810	Communications Telephone Equipment	5.00%	49,000.00	(24,500.00)	24,500.00	2,450.00
	Total		2,048,600.00	(583,915.00)	1,464,685.00	200,086.00

Attachment B

Deloitte & Touche Report

Deloitte & Touche

Terasen Inc.

Regulatory Cost Allocation Study

Final Report

October 29, 2003

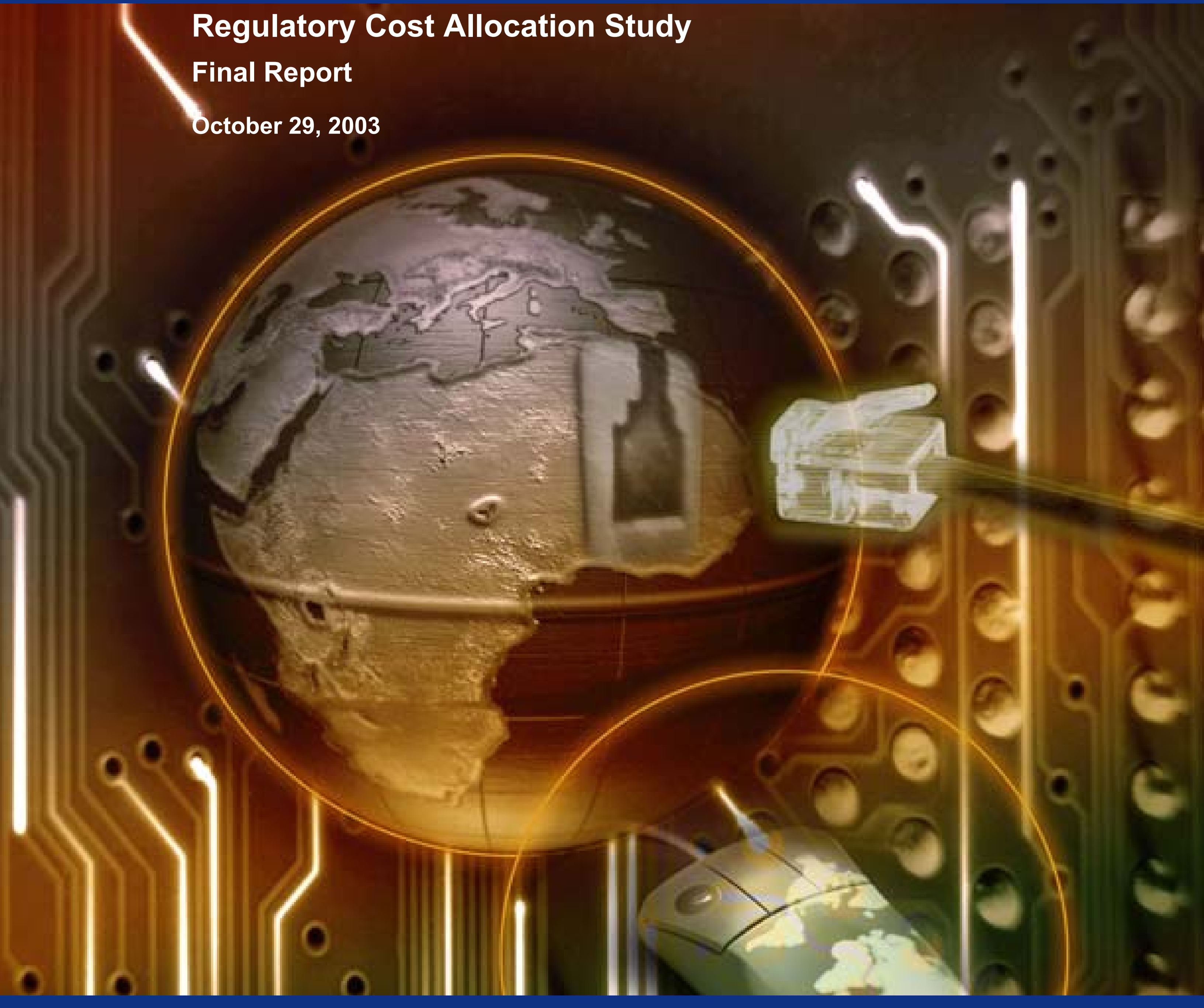

Table of Contents

1 Executive Summary

Deloitte & Touche LLP (D&T) was engaged to assist Terasen Inc. in developing an approach to allocate corporate service costs from the holdings company (Terasen Inc.) to the Regulated and Non-Regulated Businesses. The total cost for these corporate services is between $15 million and $20 million.

I. Determining the Allocation Method

Prior to the implementation of any cost allocation methodology, it is first necessary to define objectives against which to evaluate each method. There are four objectives applicable to cost allocation in a regulatory environment. The approach should a) demonstrate a causal link between activities undertaken and the "cost object" that is causing that activity to take place; b) be both supportable and reasonable; c) be efficient to administer; and d) be flexible and responsive to organizational and environmental change.

The next steps are to:

- Identify and understand the various costs which must be allocated;
- Determine how these costs should be measured; and
- Determine how the costs should be charged.

Determining costs be allocated - Costs can be grouped into three major categories: **direct, indirect** and **corporate** sustaining. These costs have a hierarchy of linkage to the activity, which is causing them to be incurred. The decision whether or not to allocate them becomes less clear as they become further removed from the delivery of products and services.

Measurement of costs - The most common units of measure include **incremental / marginal cost, fully embedded cost, and market cost.** There are several influencing factors in determining the best unit of measure such as; the primary reason for the activity to be conducted, and whether an external market for the service exists whereby the company could be purchasing the same or similar service from a third party. Answers to these and other influencing questions may affect the measure to be used.

Method of charging - There are three principal approaches used to allocate costs in the regulatory environment. These are the **formula, time sheet based and the volumetric drivers approaches**. These approaches aim to drive costs to business units in relation to consumption. The formula based method uses broad measures such as revenue or salaries as a proxy for how much consumption of a given activity may take place. The time sheet approach is very specific for the labour element of the costs to be allocated and the "volumetric driver" approach breaks costs down by activity performed and attaches a specific driver to each activity commensurate with how that activity is consumed. For instance, payroll processing may be allocated based on the number of payroll cheques produced and Information Technology costs may be allocated based on the number of computers in use.

II. Recommendation

In reviewing each cost allocation method against the defined objectives and taking into account the characteristics of the cost categories, it appears that the most appropriate solution is one that combines allocation methods. These results are summarized in the table below.

COST TYPE	UNIT OF MEASURE	ALLOCATION METHOD
DIRECT COSTS		
Clearly Attributable	▪ Fully embedded	▪ Timesheet
Repetitive & Consistent	▪ Fully embedded	▪ Volumetric Driver
INDIRECT COSTS	▪ Fully embedded	▪ Formula
CORPORATE SUSTAINING COSTS	▪ Fully embedded	▪ Formula

2 Introduction / Nature of the Engagement

Terasen Inc. is a leading energy distribution and transportation company as well as a provider of services related to energy and water distribution that are both regulatory and non-regulatory in nature.

Deloitte & Touche LLP (D&T) was engaged to assist the company in developing an approach to allocate costs from the holdings company (Terasen Inc.) to the Regulated and Non-Regulated Businesses. The total cost for these corporate services is between$15 million and $20 million.

The intent of this report is not to provide specific recommendations around which costs should be included as part of corporate costs and the allocation method, which should be used, but rather, it provides a framework that can be incorporated into Terasen's internal decision-making processes for cost allocation.

3 Determining the Method of Allocation

In determining the best method of allocating common costs, it is first necessary to determine objectives against which to evaluate each method. The next step is to identify and understand the various costs, which should be considered for allocation. These costs then need to be measured and allocated. Each of these elements is discussed in the sections, which follow.

I. Objectives of Cost Allocation Principles

In applying a costing methodology, a variety of objectives need to be considered. There are four objectives applicable to costing approaches in a regulatory environment:

- The approach should demonstrate a causal link between activities and the "cost object" that is causing that activity to take place;
- The approach must be both supportable and reasonable;
- The approach must be efficient to administer; and
- The approach must be flexible and responsive to organizational and environmental change.

Causal Link between Activities and Cost Objects

The underlying principle for the allocation of costs must be based on what is causing that cost to be incurred. The driver of that cost can be viewed in many different ways: head count, number of customers, volume of vouchers or even square footage. As such, the allocation of costs to cost objects based on their linkage should be performed at the activity level through the use of appropriate cost-drivers.

Supportable and Reasonable

In addition to establishing a link between activities and products or services, the approach of cost allocation must be both supportable and reasonable. This will provide a framework that can trace a resource (labour, expenses, occupancy, etc.) from its root to the final product or service cost. Reasonability is achieved when the approach a) produces results that are consistent with expectations, and b) demonstrates a clear understanding of the products and services each business unit provides and what products and services (if any) they support in any other areas of the organization.

Ease of Administration

Cost allocation models can become overly complex and extremely time consuming and costly to administer. A properly developed cost allocation approach and resulting model should not become a burden on the organization, but rather should involve minimal time to update and administer.

Flexible and Responsive

The need for a cost allocation approach that is flexible and responsive to organizational and environmental change is important. Without flexibility and responsiveness, the methodology will continually have to be modified and updates to the modeling tool will result. This becomes inefficient and brings into question the completeness and appropriateness of the approach if it does not have the ability to apply to changing circumstance.

II. Identification of Cost Objects

Cost objects can be defined as any activities for which a separate measurement of cost is desired. Once the pool of costs has been identified, they then need to be reviewed by major cost or activity type. Cost types can be broken down into three major groupings. There is a hierarchy associated with these costs. The decision whether or not to allocate the cost type becomes less clear as they become further removed from the delivery of the product. The three major cost categories are as follows:

- Direct Costs
- Indirect Costs
- Corporate Sustaining Costs

Direct Costs

Direct costs are those that can be clearly attributed to one product / service; or one business segment; or one specific operation in the process. In addition, direct costs are often repetitive and consistent over time in relation to the level of effort per unit of service provided.

Some examples of direct costs include:

CLEARLY ATTRIBUTED	REPETITIVE & CONSISTENT OVER TIME
▪ Legal services	▪ Accounts Payable
▪ Financial Analysis	▪ Payroll
▪ Taxation	▪ Call Centre

Indirect Costs

Indirect costs can be defined as those costs, which are further, removed from and cannot be directly attributed to specific products, organizational units or activities, but may support activities associated with those products and / or organizational units. Examples of indirect costs are administrative costs, rent, and information technology. These costs, while they do not demonstrate the strongest causal link to a specific product or process, directly support the direct costs described above and often, the direct cost activities could not take place without these indirect costs being incurred.

Corporate Sustaining Costs

Corporate sustaining costs refer to activities undertaken to support the organization as a whole and benefits all business units. Examples of corporate sustaining costs include investor relations, director fees, internal audit, executive salaries and audit fees.

Inherent in its definition, direct costs must demonstrate a clear link between cost and a product / service, business segment or process. This being the case, the decision to allocate direct costs is clear. The question then becomes which indirect and corporate sustaining costs should be allocated. In determining this, it is necessary to understand whether the indirect or corporate sustaining costs support or aid in the delivery of product/service or whether the costs are incurred as a result of doing business.

III. Measurement of Cost

There are many different ways to measure effort. The most common units of measure include Incremental / Marginal Cost, Fully Embedded Cost, and Market Based Cost.

Incremental or marginal cost is essentially variable cost. It is the additional cost involved in taking a particular course of action, such as increasing production levels.

Fully Embedded Costs layer semi-variable and fixed cost elements onto the marginal or variable costs.

Market Based Cost is the cost that would be incurred if a third party were to provide the service i.e. outsourced payroll processing.

There are several influencing factors in determining which unit of measure to use. Some of these factors include:

I. the primary reason for the activity to be conducted; and

II. whether an external market for the service exists whereby the company could be purchasing the same or similar service from a third party.

Regardless of these influencing factors, regulators generally maintain the position that the underlying principle to be used in determining unit of measure is that the ratepayer not subsidize the activities of non-regulated businesses.

IV. Cost Allocation Methods

There are three principal approaches that can be used to allocate costs. These are the ***Formula, Time Based*** and ***the Volumetric Drivers Approaches***. These three approaches are all methods to drive costs to business units in relation to consumption. As such, each uses a form of **cost driver** as its basis. Each of these approaches is discussed below, focusing in greater detail on their objectives, advantages, and descriptions of their application.

1. Formula Approach

The formula approach was developed in order to provide a means of allocating common costs (i.e. those that cannot be directly charged). These costs are grouped into one cost pool and are charged to the various business segments on the basis of a mathematical formula. One such formula, the **Massachusetts Formula**, is in extensive use in the industry. This formula allocates costs based on the arithmetical average of: (1) operating revenue, (2) payroll, and (3) average net book value of tangible capital assets plus inventories. The rationale for the inclusion of revenues, payroll, and capital assets in the calculation, is that collectively, these factors represent the total activity of all business segments. In addition, the use of these factors takes into account different business environments i.e. capital intensive and labour intensive businesses. The Massachusetts Formula has been modified by several utilities in the United States resulting in the **Kansas/Nebraska Formula.** This formula is identical to the Massachusetts Formula, except that it excludes operating revenue in the calculation of the average.

Benefits and Disadvantages

The most significant advantage of the formula approach is that it is easy to implement and administer the allocation of common costs. All that is required is that the pool of common costs be kept to a minimum. Furthermore, the use of a formula removes the use of judgment and thus eliminates any subjectivity, which might enter into cost allocation decisions.

The most significant drawback of the formula approach is that it is mathematical. Mathematical approaches do not take into account special business circumstances when allocating common costs. There may be specific circumstances where a different factor or factor weighting (i.e. other than proportionate) is justified thereby generating drastically different results. A second drawback is the formula approach does not allow corporations to recognize that certain business activities, even if not directly attributable to a business segment, may be viewed as supporting one business segment or another to a degree not properly reflected by a mathematical formula. This situation is fairly common and is one of the reasons why other methodologies (i.e. time sheets and volumetric drivers) have been developed. Finally, the formula approach suffers from the fact that it cannot be readily changed to suit changing circumstances.

2. Time Sheet Approach

The time sheet approach typically only applies to the labour component of cost and requires the following components:

- a listing of business segments which will be allocated common costs;
- periodic (e.g. weekly, monthly) completion of time sheets by employee or department; and
- accumulation of time sheets by the accounting department for the calculation of period charges to each segment.

Some time sheet based systems include budgeted allocations allowing for comparisons to actual time spent performing activities for a business unit. In addition, some utilities use a reporting mechanism that provides employees with information about cumulative reported and/or budgeted time by segment, allowing for reasonability checks and an opportunity to improve future time reporting.

The principal objective of the time sheet approach is to use employee input in the cost allocation process. In this way, an audit trail is also developed to provide the "how and why" behind cost allocations.

Benefits and Disadvantages

The primary benefit of the time sheet approach is the increased accuracy of cost allocation. Having employees track time spent on major activities (e.g. legal or tax services) for various business segments, demonstrates a clear linkage between activity and cost. A second advantage to this approach is that it allows the organization the flexibility to allocate costs on a budgeted or real time basis (e.g. weekly).

Time sheet based allocation systems do have significant drawbacks. Most time sheet systems require a feedback loop in order to provide the benefits of recording and maintaining detailed time reporting information. Often, comprehensive feedback reporting systems are costly to implement, and perhaps even more costly to maintain. Time sheet approaches rely on the employee to track time and expenses and enter them on a regularly basis allowing for clerical error. Organizations must then review and verify input, and generate reports. This often requires extensive payroll, data input, information systems and other support staff involvement.

3. Volumetric Driver Approach

The volumetric driver approach operates on the principle of identifying a link between specific types of expenses or activities and business segments. The methodology requires that costs similar in behaviour are grouped and that volume drivers be defined. The costs within a cost pool can then be charged to business segments based on a volumetric driver. This approach is best suited to service organizations which process standard transactions as opposed to service organizations, which primarily provide labour, based services. Cost pools and drivers must be established with two thoughts in mind: the driver volumes must reflect the effort spent by staff on specific activities; and the use of drivers must fairly attribute costs to business segments. Costs not consumed in a consistent manner do not lend themselves to this approach.

Examples of Volumetric Drivers

The following table illustrates examples of selected cost centres and lists potential drivers for all or part of each cost centre.

COST CENTRE	TYPICAL ACTIVITIES OR EXPENSES	POTENTIAL COST DRIVERS
Accounting department	▪ Accounts Payable	▪ Estimated number of accounts payable vouchers
Customer service	▪ Billing	▪ Number of customers
Accounting department	▪ Payroll	▪ Head count
Accounting department	▪ Processing journal vouchers	▪ Number of journal vouchers
Administration	▪ Property maintenance	▪ Head count
Information systems	▪ Systems Development	▪ Allocated to departments based on application and then allocated based on the composite ratio for that department

Benefits and Disadvantages

The key benefit of the volumetric driver approach is that it is entirely objective. Once in place, the volumetric driver calculates the proportion of each department's cost that is attributable to each business segment based strictly upon the transaction volumes of the pre-set drivers.

The most significant drawback of this approach is the effort required to set it up. Cost drivers must be defined and cost pools created. However, once these elements are defined automated systems can be used to capture this information thus reducing effort required for ongoing maintenance. Finally, the volumetric driver approach must be monitored on a periodic basis in order to ensure that the volumetric drivers themselves remain current and reasonable. This can be accomplished through discussions with department managers to ensure that individual drivers adequately measure costs.

4 Evaluation & Recommendation

In reviewing each cost allocation method against the objectives initially defined (see table below), it appears that the volumetric driver approach emerges as a preferred approach.

		COST ALLOCATION METHOD		
		FORMULA BASED	TIME SHEET	VOLUMETRIC DRIVER
OBJECTIVES	Causal link between activities and cost objects		✓	✓
	Supportable and reasonable	✓	✓	✓
	Ease of administration	✓		✓
	Flexible and responsive			✓

Evaluating the allocation methods without taking into account the various characteristics of the cost categories would not be complete. When reviewing the methods of allocation against each of the cost pools, it appears that a combination of allocation methods is a more appropriate solution. These results are summarized in the table below and then discussed in further detail.

		COST ALLOCATION METHOD		
		FORMULA BASED	TIME SHEET	VOLUMETRIC DRIVER
COST CATEGORIES	Direct Costs		✓	✓
	Indirect Costs	✓		
	Corporate Sustaining Costs	✓		

Direct Costs

Direct costs can be further segregated into those that can be clearly attributed and those that are repetitive and consistent over time as to level of effort per unit of service provided. Those labour costs that can be clearly attributed to a specific activity, process or business segment are usually measured using the marginal or fully embedded costing approach. This cost type lends itself to **time reporting** as the best method of cost allocation. As well, this method provides a strong level of detail and support and provides the strongest causal link.

Direct costs, repetitive and consistent in nature, are best driven by **volumetric measures** that are causing the activity to be performed and therefore the cost to be incurred. The formula approach is too broad brush for this application and the time sheet approach does not provide a better result and is more costly and time consuming to administer. These cost types are best measured in the application of a fully embedded costing philosophy.

Indirect Costs

As these activities and related costs typically directly support other activities, they are usually best handled in the same proportion as the activities, which they are supporting. This normally takes the form of a composite ratio **(formula)** of the allocation split of the activities that are being supported. These cost types are more commonly measured utilizing a fully embedded costing philosophy.

Corporate Sustaining Costs

The corporate sustaining cost category is best suited to a **formula based** cost allocation approach, as these costs are normally consumed based on high-level factors such as revenues, rate base and salaries. This cost pool is typically only allocated, if at all, in the application of a fully embedded costing philosophy. The true relationship between activity and cost object is not very clear using this approach, however, a more detailed cost driver would have no more validity and therefore would not produce a more supportable result.

Scott A. Thomson
Vice President,
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May 31, 2004

British Columbia Utilities Commission
Box 250
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Mr. R.J. Pellatt

Dear Sir:

Re: Terasen Gas Inc. and Terasen Gas Vancouver Island
Shared Services Management Agreement

During the regulatory rate setting process for test years 2003 and 2004, Terasen Gas Inc. indicated that the acquisition of Centra BC (TGVI) and Centra Whistler would provide an opportunity to create synergies. A number of synergies were identified and reflected in 2003 revenue requirements and by formula into the 2004 rates of Terasen Gas Inc. (TGI). Similarly, savings accruing to TGVI were included in its revenue requirement filing in the fall of 2003.

TGI and TGVI have now undertaken a major restructuring initiative which will deliver substantial savings for the two companies. A single management team is now in place and common work processes and information technology platforms are being developed and implemented to create a more cost effective and sustainable support organization. The operational integration of TGI and TGVI require significant upfront investments in process changes and organizational restructuring. Capital investments totalling some $8 million are expected to be incurred to harmonize the information technology platforms including the transfer of a 10% interest ($2.4 million) in the net book value of the SAP platform of TGI. In total, $15.5 million have or will be incurred on restructuring, resulting in a net staff reduction of 115 employees. These upfront investment costs are expected to generate sustainable annual savings exceeding $10 million per year between the two companies.

With a single management and support team, services will be delivered on a shared basis. Utilizing a framework similar to that used by Terasen Inc. to allocate corporate centre management fees to TGI, an allocated shared services cost for the provision of shared services to TGVI is estimated to be $2.8 million for 2004. This annual allocated shared services cost will be trued up at year end when actual shared costs are known. TGVI and its customers are expected to realize net annualized benefits of approximately $2.0 million once all costs including shared service cost allocations are factored in. Terasen undertook this restructuring initiative to provide long term benefits to customers of both utilities and their shareholders.

Details of the restructuring initiative, derivation of the annual allocated shared services cost and expected savings can be found in the attached Shared Services Management Report and Agreement.

Should you have any questions, please contact the undersigned at 604-592-7784.

Yours very truly,

TERASEN GAS INC.
Per:

Original signed by:

Scott A. Thomson
Vice President, Finance and Regulatory Affairs

Attachments

Shared Services Management Report

Terasen Gas Inc. and Terasen Gas Vancouver Island

May 31, 2004

Shared Services Management Report

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.

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1.0 Executive Summary

The operational integration of Terasen Gas Inc. (“TGI”) and Terasen Gas (Vancouver Island) Inc. (“TGVI”) began in earnest September, 2003, with organizational design and plan development completed in December. Implementation of the organization and associated plans began immediately afterward and is currently ongoing. The integration exercise facilitates a shared services approach that enables both companies to harness the benefits from economies of scale by having a single management and support structure that avoids duplication of work and allows customers to benefit from the synergies created.

As a result of the restructuring initiative, TGI and TGVI are collectively expected to incur one-time restructuring charges of $15.5 million due to having 115 fewer employees. TGI and TGVI’s respective share of the restructuring costs are expected to be $11.3 million and $4.2 million. Additionally, TGI and TGVI are expected to realize net savings of $8.0 million and $2.5 million for a total net savings of $10.5 million in 2004. For 2005, the anticipated net savings are expected to be approximately $9.9 million in total for the two utilities after giving effect for the additional revenue requirement resulting from capital investments at TGVI. The resulting total cumulative savings over the 2004/2005 period is expected to be $20.4 million, resulting in a net benefit over two years of $4.9 million and ongoing benefits of approximately $10 million/year, to be shared with customers according to the respective negotiated rate settlements of the two utilities. Beyond this short payback period, customers of both utilities will enjoy the benefits of lower costs as a result of the operational integration undertaken. It is also anticipated that capital investments totaling approximately $8 million are required in the 2004/2005 period to allow for a shared information technology platform, and 10% of the net book value or $2.4 million of SAP will be transferred to TGVI as part of the shared information technology strategy.

To deliver on the synergies created, both utilities moved to a shared services platform whereby the costs of management and back office support are aggregated in TGI and then allocated to TGVI. The amount of the annual shared services costs that will be subject to allocation from TGI to TGVI is estimated to be approximately $28.9 million in 2004. This results in an estimated allocation to TGVI of $2,770,000 for 2004, which is subject to true up to actual costs. This amount will be reviewed and reforecast each year and adjusted for changes in resource levels. In addition to this allocation, an estimated $290,000 of shared service costs will be charged directly to various TGVI O&M accounts from TGI and approximately $151,000 of OPEB’s will be allocated directly from TGI to TGVI. This results in a total transfer of costs from TGI to TGVI of approximately $3.2 million in 2004.

2.0 Introduction

This document sets out the basis and rationale for a shared services management agreement between TGI and TGVI. Recent organizational restructuring, also referred to as integration, has resulted in the creation of a single management structure providing direction and services to both TGI and TGVI. This restructuring will enable both companies to harness the benefits from economies of scale by combining certain management and back office support activities of the two entities. A single management and support structure allows the companies to maintain an optimal level of resources, avoid duplication of work, and provide customer benefits from realized synergies.

This document includes:

(1) An overview of the integration effort;
(2) Explanation of the savings due to operational integration;
(3) A description of the shared services to be provided;
(4) The cost allocation approach used for the provision of those services; and
(5) The cost allocation methodology to be employed.

Also included, is the Shared Services Management Agreement. This agreement, which is included as Appendix A, provides transparency in separating the operating costs of the separate regulated entities and reduces administrative burden.

3.0 Overview of the Integration Initiative

The integration initiative, referred to internally as the Utilities Strategies Project ("USP"), commenced September 10th, 2003 with the planning and organizational design work completed on December 12th, 2003 followed by the execution phase which is ongoing. The USP was established to plan and implement a single management team, along with common work processes and IT platforms in order to create a more cost effective and sustainable support organization across Terasen Inc.'s natural gas utilities (TGI, TGVI, TG Squamish and TG Whistler).

The USP built on the Company's solid foundation of Operational Excellence in core activities (safety, customer satisfaction, cost, and environmental stewardship). It was broad in scope and scale, while respecting existing legal, regulatory and contractual obligations. Care was taken to be respectful and fair to employees, customers, shareholders, and the communities served and to result in sustainable, more effective, efficient gas utilities.

A number of guiding principles were employed in carrying out the project:

- The business approach and IT platforms were to be common barring compelling reasons to do otherwise.
- "Best practice" solutions were to be identified.
- Conversion costs of historical data were to be minimized while maintaining retrieval capability.
- Separate legal entities, rate bases and rate design were to be maintained.
- Cost efficiencies were expected to flow to both entities' customers according to their separate regulatory frameworks.
- Cost driver information was to be captured to ensure proper allocation of costs and savings.
- Common compensation practices for all employees were to be developed along with the goal to move to common employer status with bargaining units.
- Staffing decisions were to seek retention of the best people from both organizations.

Business process teams were established to evaluate the current business processes and to identify and recommend best practice process solutions. Representatives from Field Operations, Finance & Regulatory, Customer Care & Marketing, Human Resources, SAP Back Office Implementation, and IT & Facilities from each utility made up the business process teams. The work was carried out using a phased approach as follows:

1 – Planning

- Definition of the scope of the work.
- Project Charter development.
- Develop overall project plan.

2 – Current State Documented

- Map the TGVI and TGI "As Is" state at each functional area.

3 – Analysis

- Analyze "As Is" state.
- Identify opportunities for improvement.

4 – Design

- Design future "To Be" state.
- Identify organizational changes (inclusive of staffing requirements).

5 – Recommendation & Implementation Planning

- Develop and present recommendations to senior management regarding processes, technology and organizational structure.
- Conduct Staffing Process to retain most suitable employees from both organizations to meet daily operational requirements and future business needs.

From a governance perspective, a Policy Team was established to deal with issues related to Integration Philosophy, Human Resources Policies, Staffing Process, Early Retirement Options, briefing of senior management and other policies as required.

The planning and organizational design phase of the USP concluded in late 2003 and culminated with an internal announcement on December 12, 2003 of a new, single management team for Terasen Gas group of utilities. With the organizational blueprint in place, the companies will be in a transitional phase during 2004 as new initiatives are implemented to achieve a high degree of operational integrated by January 1, 2005. Major efforts are currently underway to ensure full integration of the management and business processes of the utilities. Many employees have assumed new roles and responsibilities as a result of the new organizational structure. Due to the organizational changes, new cost centres were needed to capture common cost pools and an allocation methodology had to be developed to ensure common costs are allocated to the respective utilities in a manner that avoids cross subsidization. Section 7.0 of this document describes the basis of the allocation methodology. Financial and statistical data resulting from the operational integration is described in the following section.

4.0 Savings due to Operational Integration

In order to complete the operational integration of the utilities, the Companies have made significant upfront investments in process changes and organizational restructuring in order to realize ongoing cost savings. TGI and TGVI will incur one-time restructuring charges totalling approximately $15.5 million. The majority of these costs were incurred in 2003 and result primarily from net staff reductions totalling 115 employees. A breakdown of the restructuring costs is summarized in Table # 1 below and the associated staff reduction levels are summarized in Table # 2.

Table # 1

Breakdown of Restructuring Costs ('000's)	TGI	TGVI	Total
Early Retirement and Severance Costs - 2003	$ 9,042	$ 2,231	$ 11,273
Related Restructuring Costs Incurred -2003	529		529
Sub-total	$ 9,571	$ 2,231	$ 11,802
Severance and related costs – 2004 & beyond	1,733	1,973	3,706
Total Restructuring Cost	**$ 11,304**	**$ 4,204**	**$ 15,508**

Table # 2

Summary of FTE reduction by department									
Business Unit	Pre-Integration FTE			Post-Integration FTE			Net FTE Reduction		
	TGI	TGVI	Total	TGI	TGVI	Total	TGI	TGVI	Total
Gas Supply & Transmission	97	14	111	96	11	107	1	3	4
Finance, Regulatory & President	51	16	67	48	-	48	3	16	19
Distribution	696	102	798	682	97	779	14	5	19
Business & IT Services	89	13	102	77	-	77	12	13	25
Operations Governance & Support	152	15	167	142	5	147	10	11	20
Marketing	77	43	120	70	36	106	7	7	14
HR	40	5	44	30	-	30	9	5	14
	1,201	**207**	**1,408**	**1,145**	**148**	**1,293**	**56**	**59**	**115**

In order to optimize the back office support functions, the integration also requires TGVI to make capital investments to harmonize Information Technology platforms and processes totalling approximately $8 million in 2004/2005. Refer to Table # 3 below for a breakdown of these costs. In addition, TGI will transfer to TGVI a 10% interest in the net book value of the SAP technology platform assets it will use to provide the services under this agreement. This will preserve the nature of the costs associated with the rate base of these assets as they are utilized. The NBV of the 10% interest is $2.4 million. The 10% figure was arrived at after consideration of the relative proportion of TGVI vs. TGI employees (11.5%) and TGVI vs. TGI customers (9.0%). A simple average of the two factors was rounded to 10%, for purposes of this calculation. These factors are described under Section 7.0 of this document.

Table # 3

Summary of Capital Investments	TGI	TGVI	Total
Order Fulfillment System		$ 1,900	$ 1,900
Back Office Business Support Integration		1,500	1,500
Meter Mgt & Mobile Systems Integration		1,800	1,800
AM/FM/Drafting Systems		700	700
Infrastructure and Operational Integration		1,400	1,400
Others		700	700
Sub-total		**$ 8,000**	**$ 8,000**
10% of SAP NBV transfer	$ (2,380)	2,380	-
Total	**$ (2,380)**	**$ 10,380**	**$ 8,000**

As part of the integration, the company is planning to convert TGVI's customer information system (Banner), which is currently outsourced to Enlogix, to the Energy system used by TGI. The customer care function of TGVI including billing and call handling will likely be contracted with Accenture Business Services when the conversion takes place. As this project is currently in the feasibility stage, the timing and projected cost of the conversion and related benefits have not been included in this report.

The operational integration initiative is expected to generate annualized O&M savings of approximately $10.8 million in 2004 and rising to more than $11 million in 2005 and thereafter. The overall net anticipated savings, due to the operational integration inclusive of depreciation, tax impacts, etc., related to the capital investment and asset transfer described earlier, is summarized in Table # 4 below:

Table # 4

	2004			2005 (1)		
	TGI	TGVI	Total	TGI	TGVI	Total
Annualized O&M Savings due to Restructuring	$ 4,356	$ 6,400	$ 10,756	$ 4,356	$ 6,700	$ 11,056
Capital Investment Related						
$8 million Capital Investment	-	(164)	(164)	-	(1,138)	(1,138)
10% of SAP transfer	418	(459)	(41)	366	(406)	(40)
Shared Services Costs Allocated & Direct (2)	3,211	(3,211)	-	3,211	(3,211)	-
Net Anticipated Savings	**$ 7,985**	**$ 2,566**	**$ 10,551**	**$ 7,933**	**$ 1,945**	**$ 9,878**

(1) Note – the 2005 costs are estimates only as these are subject to annual renewals to allow for increases or decreases in associated resource levels and associated projected system integration.

(2) Note – the Shared Services costs are described under section 7.0 of this document.

The combined net anticipated savings of $10.5 million in 2004 and $9.9 million in 2005, represents a two year total of $20.4 million. This net savings is $4.9 million greater than the restructuring charges of $15.5 million, resulting in an estimated net benefit of integration of $4.9 million over the 2004/2005 two year period.

5.0 Scope of Shared Services Covered

Although the USP had as its scope, all of the Terasen Gas group of regulated utilities, the focus to date has been primarily on TGI and TGVI, due to their scale. Furthermore, there are currently agreements in place between TGI and Terasen Gas Squamish ("TGS") as well as between TGVI and Terasen Gas Whistler ("TGW") regarding the allocation of costs. As a result, the following sections of this document focus on the integration of TGI and TGVI and the need for shared services between those two entities. The existing agreements with TGS and TGW will continue and are therefore out of scope for this Shared Services Management Agreement.

The operational integration of TGI and TGVI facilitates a shared services approach that enables both companies to harness the benefits from economies of scale by having a single management and support structure. Common services, described summarily below, are being provided on a shared basis by the single management structure in order to meet each company's operating requirements. By restructuring the delivery of these services on a shared basis, the costs can be optimized across the entities to the benefit of all customers.

The common services that are delivered on a shared basis can be broken down into the following major functional areas:

- President's Office
- Finance and Regulatory Affairs
- Human Resources
- Operations Governance and Support
- Gas Supply and Transmission
- Business and Information Technology Services
- Distribution
- Marketing

These are described in detail in Schedule "A" of the Shared Services Management Agreement.

The benefits of providing the above noted services centrally are cost efficiency and a higher standard of service. A single management and support structure allows the companies to maintain an optimal level of resources, avoid duplication of work, and customers will benefit from synergies.

The integration process, as part of the USP, commenced in some departments effective Jan 1, 2004, and work will continue throughout 2004 and beyond to integrate technology platforms and business processes. However, it should also be noted that certain integration activities pre-dated the USP. Several agreements currently exist between TGI and TGVI for the delivery of specific services. These services include Gas Control, Core Market administration, Measurement and Instrumentation. The existing agreements for the provision of these services will continue, and are therefore out of scope for the Shared Services Management Agreement.

As noted, existing contracts with TGVI will continue in effect except for Core Market Administration. Prior to the recent restructuring, TGI provided trading and risk management services to TGVI for an annual fee of $100,000. With the recent changes, Gas Supply has assumed all gas supply related activities for TGVI and now oversees the entire cost of gas amount. As a result of this change, TGI will now charge TGVI an amount of $356,900 per annum or $29,742 per month for services relating to Core Market Administration.

6.0 Cost Allocation Approach used for Shared Services Costs

As described in previous sections of this document, the USP led to the establishment of a single management team and organization for both entities. One of the requirements resulting from the operational integration of the two companies was to establish a fair and reasonable cost allocation approach to share costs between the two regulated entities. In arriving at the cost allocation approach used, the Company drew from the report prepared by Deloitte & Touche that presents a framework based on generally accepted methods of allocating shared services costs to affiliates (filed as part of the Terasen Corporate Separation Study, Section B, Tab 9 of the 2003 Annual Review). This report was commissioned by Terasen Inc. (TI) and used in establishing the cost allocation basis for management services provided by TI to TGI commencing January 1, 2004. The framework used as the basis for the allocation of Shared Service costs is consistent with the approach used by Terasen Inc. The British Columbia Utilities Commission ("the Commission") approved the cost allocation fee to TGI in its Decision dated December 17, 2003 via Commission Order No. G-80-03.

In addition, the Company created guiding objectives for the development of cost allocation approach. These guiding objectives were to ensure:

- The avoidance of cross subsidization between regulated entities.
- The establishment of procedures that are efficient to administer and account for.
- The creation of a methodology that is reasonable, flexible and responsive to organizational changes.
- The demonstration of a causal link between the allocation of cost and the cause of the costs incurred through the use of cost drivers.

7.0 Cost Allocation Methodology

The operating expenses of each utility are comprised of direct expenses and shared services expenses. The shared service expenses relate to tasks performed centrally and the majority of costs to provide these types of services are fixed in nature. Once office facilities, staff and associated processes and systems have been established, the incremental cost to provide additional services is marginal. Providing the service centrally maximizes the utilization of the fixed costs resulting in cost efficiency. To deliver on the synergies created by this centralization, the Company moved to a shared services platform whereby the costs of management and back office support are aggregated in TGI and then allocated to TGVI.

A review of all departmental activities in the company was conducted of the common services and/or management responsibilities for operations or activities of the two entities. A determination was made of the most appropriate basis to recover costs relating to the services provided to TGVI, either through a cost allocation calculation or through a direct assignment basis utilizing timesheets.

The common services were described in summary fashion, under Section 5 above and are listed in detail in Schedule “A” of the Shared Services Management Agreement. Many of these services relate to policy, strategy and governance activities in addition to high value skills delivery in specialized areas. A significant portion of these expenses, such as human resources and regulatory support, for example, are most appropriately recovered via an allocation process. However, some of these services such as engineering services can more effectively be charged directly based on timesheet information.

All of the shared services costs were reviewed with respect to the utilization of the most appropriate allocation method and the allocation of the shared service costs to TGVI can be broken down into the following two categories, which are summarized below:

- Direct Charges - costs such as TGVI field operations costs and Commission assessment fees that can be clearly attributed to TGVI will be charged *directly* to TGVI. Support department staff including engineering, drafting, and information technology services and enterprise resource planning employed by TGI will provide services to TGVI and will charge their costs to TGVI via timesheets, consistent with the Transfer Pricing policy.

- Allocations - costs incurred in departments such as HR, Finance and Information Technology that are not involved with the direct delivery of services to end customers will be captured in departmental cost pools and then *allocated* to TGVI based on the allocation factors included in Table # 5 below:

Table # 5

	Expressed as Numbers			Allocation Factors Expressed as %s		
COST DRIVERS	**TGI**	**TGVI**	**Total**	**TGI**	**TGVI**	**Total**
Number of Customer	775,516	76,842	852,358	91.0%	9.0%	100.0%
Number of Employees (FTE/s)	1,142.2	148	1,290.2	88.5%	11.5%	100%

Based on the allocation factors described above, table # 6 below sets out the shared service costs to be *allocated* to TGVI for 2004:

Table # 6

Shared Service Costs To be allocated	**Cost Driver***	**Total ($000)**	**Allocation Factors***	**Allocated ($000)**
President	# of Customers	$ 1,235	9%	$ 111
Finance & Regulatory	# of Customers	5,313	9%	479
Human Resources	# of Employees	3,119	11.5%	358
Operations Governance & Support	# of Customers/# of Employees	5,732	9.7% *	557
Gas Supply & Transmission	# of Customers	2,186	9%	197
Business & IT Services	# of Customers/# of Employees	2,940	10.8% *	317
Distribution	# of Customers	4,132	9%	372
Marketing	# of Customers	4,199	9%	379
TOTAL		**$ 28,856**		**$ 2,770**

Where more than one cost driver is used, the cost pool for allocation is segregated by cost driver. The weighted average for the organizational unit is reflected in the table above.

The amount of the annual shared services cost allocation from TGI to TGVI, is estimated at $2,770,000 for 2004. This amount will be subject to a true up at year end when actual shared costs are known. The shared services allocation charges will be in accordance with the shared services agreed to in the contract. Any services not previously contemplated will be provided in a separate supplement to the agreement. The cost allocation will be updated prior to the start of each year and adjusted for changes in anticipated resource levels accordingly.

Shared service costs to be recovered by TGI from TGVI by direct charge for 2004 are estimated at $290,000. Additionally, OPEB's, which are directly attributable to TGVI staff will be allocated directly to TGVI from TGI. The allocation of OPEB's to TGVI is estimated at $151,000. The total shared service costs that will be allocated and charged directly from TGI to TGVI is estimated at $3,211,000, as set out in table # 7 below.

Table # 7

	2004 Total
Allocation of Shared Services Costs	2,770
Direct OPEB Costs	151
Direct Timesheet based Charges to O&M	290
Total Shared Services Costs – Direct and Allocated	**$ 3,211**

Appendix A

Shared Services Management Agreement

THIS AGREEMENT made as of and effective January 1, 2004

BETWEEN:

TERASEN GAS (VANCOUVER ISLAND) INC.
1675 Douglas Street,
PO Box 3777
Victoria, British Columbia
V8W 3V3

(**"TGVI"**)

AND:

TERASEN GAS INC.
16705 Fraser Highway,
Surrey, British Columbia
V3S 2X7

(**"TGI"**)

WHERAS

A. TGVI is the owner and operator of the natural gas transmission and distribution facilities in British Columbia serving the communities of Vancouver Island and the Sunshine Coast (the "Facilities"); and

B. TGVI wishes to retain TGI to provide certain administrative and management services to it in respect to the ownership and common management of the operation of operations of its transmission pipeline and distribution business on the terms and conditions set out herein.

WITNESSES that, in consideration of the covenants and agreements herein contained, the parties covenant and agree as follows:

PART 1

INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement

(a) "**Applicable Laws**" means any and all Laws in force and effect from time to time and applicable to the Facilities and the performance of the Services hereunder;

(b) "**Force Majeure**" has the meaning assigned to such term in Section 9.1;

(c) "**Governmental Authority**" means any domestic or foreign, national, federal, provincial, state, municipal or other local government or body and any division, agent, commission, board, or authority of any quasi-governmental or private body exercising any statutory, regulatory, expropriation or taxing authority under the authority of any of the foregoing, and any domestic, foreign, international, judicial, quasi-judicial, arbitration or administrative court, tribunal, commission, board or panel acting under the authority of any of the foregoing;

(d) “**Laws**” means all constitutions, treaties, laws, statutes, codes, ordinances, orders, decrees, rules, regulations and municipal by-laws, whether domestic, foreign or international, any judgements, orders, writs, injunctions, decision, rulings, decrees, and awards of any Governmental Authority, and any published policies or guidelines of any Governmental Authority and including, without limitation, any principles of common law and equity,

(e) “**Person**” includes any individual, corporation, body corporate, partnership, joint venture, association, trust, estate, incorporated or unincorporated association, any government or governmental authority however designated or constituted or any other entity of whatever nature,

(f) “**Services**” means the administrative and management services to be provided to TGVI by TGI as more particularly described in Section 2.1.

1.2 Schedules

The following are the schedules attached to, and are incorporated by reference into, this Agreement:

Schedule “A”	Description of Services
Schedule “B”	Pricing

1.3 Interpretation

In and for the purpose of this Agreement

1) this “Agreement” means this agreement as the same may from time to time be modified, supplemented or amended in effect,

2) any reference in this Agreement to a designated “Article”, “Section” or other subdivision is to the designated Article, Section or other subdivision of this Agreement,

3) the words “herein”, “hereof” and “hereunder” and other words of similar import refer to this Agreement as a whole and not to any particular Article, Section or other subdivision,

4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement,

5) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word “or” is not exclusive and the word “including” is not limiting (whether or not non-limiting language (such as “without limitation” or “but not limited to” or words of similar import) is used with reference thereto), and

6) each word and phrase used herein and not otherwise defined herein, but which has an accepted meaning in the custom and usage of the Western Canadian oil and gas transportation industry, shall have such accepted meaning.

1.4 Governing Law

Subject to Section 9.1, this Agreement will be interpreted and the rights and remedies of the parties hereto will be determined in accordance with the laws of the Province of British Columbia.

PART 2

SERVICES

2.1 Services

TGI hereby agrees to provide to TGVI those administrative and management services described in Schedule A.

2.2 No Obligation to Provide Additional Services

TGI shall not perform, and TGI shall have no obligation to perform, any services on behalf of TGVI in respect of the Facilities other than as set out in this Agreement or any similar agreement.

2.3 Consultation with TGVI

TGI will consult with TGVI as required in connection with the performance of the Services.

2.4 Independent Contractor

Nothing in this Agreement shall be construed to create or constitute a partnership or relationship of joint venture between TGI and TGVI. In performing the Services, TGI shall be an independent contractor. TGI employees shall not be considered employees of TGVI for any purpose.

2.5 Compliance

In performing the Services, TGI will comply with all Applicable Laws.

PART 3

COMPENSATION

3.1 Compensation for Services

TGVI agrees to pay to TGI for the administration and management services the compensation set out in Schedule B.

3.2 Amendment to Costs

The amounts set out in Schedule "B" may be amended from time to time by agreement between the parties to reflect any material change in the cost of providing the services or in the business operations of TGVI.

3.3 Invoicing

TGI will invoice TGVI in respect of the Services no later than the 25th day following the end of the month in which such Services are provided or in such other manner as the parties may agree.

3.4 Payment

(a) Except with respect to those portions of an Invoice which are the subject of a bona fide dispute between the parties, invoices shall be payable within thirty (30) days from the date of the invoice.

(b) Any amount to be remitted by TGVI to TGI and not remitted on or before the date on which it is due shall thereafter bear interest at an annual rate equal to the prime rate of interest of the Toronto-Dominion Bank (or its successor or permitted assign) (Toronto, Main Branch) plus one percent (1%) calculated daily from the date the amounts become due.

(c) Effective December 31, 2004 TGI will prepare financial accounting of the actual costs and the allocated costs, and will make adjustments based on additional amount to be paid by TGVI or return an overpayment.

(d) Payments due and owing as a result of the accounting will be paid no later then the end of the first quarter of the following year.

3.5 Taxes

Notwithstanding any other provision of this Agreement, the amounts paid or payable by one party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are now, or may become during the term of this Agreement, applicable to the provision of the Services. Each party shall pay to the other party any value added taxes or sales tax which one party is obligated to collect from the other at the time such taxes are due and payable.

PART 4

INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by TGVI

Subject to Section 4.4, TGVI will indemnify, defend and hold harmless TGI and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with TGI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of TGI.

4.2 Limitation of Liability of TGI

Neither TGI nor any of its directors, officers, employees, agents or contractors will be liable to TGVI for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, or cost or expense (including reasonable legal fees and disbursements) which TGVI may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with TGI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of TGI.

4.3 Indemnity by TGI

Subject to Section 4.4. TGI will indemnify, defend and hold harmless TGVI from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award and cost or expense (including reasonable legal fees and disbursements) which TGVI may suffer or incur as a result of any act or omission or error of judgement as a result of which TGI is adjudged to have been guilty of wilful misconduct or gross negligence.

4.4 Consequential Losses

Neither party hereto will be liable to the other, whether based in contract, tort (including negligence and strict liability), under warranty or otherwise for special indirect, incidental or consequential loss or damage whatsoever, including without limitation, loss of use of equipment or facilities and loss of profits or revenues.

PART 5

COVENANTS OF TGVI

5.1 Covenants by TGVI

TGVI covenants and agrees to:

(a) fully co-operate with TGI in respect of all matters contemplated by or within the scope of this Agreement; and

(b) pay on or before the due date thereof all amounts payable by TGVI to TGI or any other Person pursuant to or as contemplated by this Agreement.

PART 6

REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of TGI

TGI hereby represents and warrants to TGVI as representations and warranties which are true as at the date hereof and which will be true during the term of TGI's appointment hereunder:

(a) TGI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and TGI has full power and authority to perform its obligations hereunder,

(b) this Agreement constitutes a valid and binding obligation of TGI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought; and

(c) TGI possesses all of the skills and personnel required to provide the Services.

6.2 Representations and Warranties of TGVI

TGVI hereby represents and warrants to TGI as representations and warranties which are true as at the date hereof and which will be true during the term of TGI's appointment hereunder:

(a) TGVI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and TGVI has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of TGVI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

PART 7

DURATION, TERMINATION AND DEFAULT

7.1 Effective Date and Term

This Agreement will be effective retroactively from January 1, 2004 and will continue until December 31, 2004. Thereafter the Agreement will automatically be renewed for further one year terms subject to Sections 7.2 and 7.3 below.

7.2 Termination

TGI's appointment hereunder may be terminated at any time:

(a) by TGI giving TGVI written notice of such termination:

(i) if TGVI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if TGVI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against TGVI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of TGVI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or TGVI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; and

(ii) in the event TGVI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by TGVI of written notice thereof from TGI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from TGI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of TGI that TGVI is in breach is conceded to be correct by TGVI or found to be correct by an arbitrator pursuant to Section 8.1;

(b) by TGVI giving TGI written notice of such termination:

(i) if TGI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if TGI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against TGI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of TGI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or TGI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; and

(ii) in the event TGI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by TGI of written notice thereof from TGVI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from TGVI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of TGVI that TGI is in breach is conceded to be correct by TGI or found to be correct by an arbitrator pursuant to Section 8.1.

7.3 Termination Without Cause

Notwithstanding Section 7.2 above either party may, upon obtaining the other party's written consent, terminate this Agreement without penalty or damages upon giving thirty (30) days written notice.

7.4 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, TGI will have no further obligations under Article 2 and will promptly deliver to TGVI any material documents in the possession of TGI pertaining to the business of TGVI.

7.5 Compensation of TGI on Expiry or Termination

Within one (1) month after the expiry or termination of this Agreement, TGVI will pay to TGI all amounts owing to TGI hereunder (including any amount owing on account of the fees provided for in Article 3 calculated up to the date of expiry or termination); provided that for the purposes of this Section, the fees provided for in Article 3 which are payable to TGI on a monthly, annual or other periodic basis will be deemed to accrue due and be payable on a daily basis.

PART 8

ARBITRATION

8.1 Arbitration

For purposes of Section 7.2, any dispute between TGI and TGVI regarding any allegation that TGVI or TGI is in breach of this Agreement, may be submitted to and settled by arbitration in accordance with the provisions of this Section 8.1. Arbitration proceedings may be commenced by the party desiring arbitration giving notice to the other party specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator and in accordance with the Rules of Procedure for Commercial Mediation of The Canadian Foundation for Dispute Resolution from time to time in force and effect. If the parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either of them may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed, which appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section 8.1 will be final and binding upon the parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both of the parties, provided that each party will bear its own witness and counsel fees. The parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgement on the award of the arbitrator may be entered in any court having jurisdiction over the party against which enforcement of the award is being sought. Each party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgement of any such award.

PART 9

FORCE MAJEURE

9.1 Force Majeure

In and for the purposes of this Agreement, “Force Majeure” shall mean anyone or more of the following events:

(a) an act of God;

(b) a war, revolution, insurrection, riot, blockade, or any other unlawful act against public order or authority;

(c) a strike, lockout or other industrial disturbance;

(d) a storm, fire, flood, explosion, earthquake or lightning;

(e) a governmental restraint; or

(f) any other event (whether or not of the kind enumerated in 9.1(a) to (e) above) which is not reasonably within the control of the party hereto claiming suspension of its obligations hereunder due to Force Majeure.

9.2 Performance Prevented by Force Majeure

If either party hereto is prevented by Force Majeure from carrying out any of its obligations hereunder, the obligations of such party, insofar as its obligations are affected by Force Majeure, shall be suspended while (but only so long as) Force Majeure continues to prevent the performance of such obligations. Any party prevented from carrying out any obligation by Force Majeure shall promptly give the other party hereto notice of Force Majeure including reasonably full particulars thereof.

9.3 Remedy of Force Majeure

A party claiming suspension of its obligations by reason of Force Majeure shall promptly remedy the cause and effect of Force Majeure described in the notice given pursuant to Section 9.2 insofar as such party is reasonably able so to do, provided that the terms of settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of the party hereby claiming suspension of its obligations hereunder by reason thereof; and that such party shall not be required to accede to the demands of its opponents in any strike, lockout or industrial disturbance solely to remedy promptly Force Majeure thereby constituted.

9.4 Lack of Funds Not Force Majeure

Notwithstanding anything contained in this Article 9, lack of finances shall not be considered Force Majeure nor shall Force Majeure suspend any obligation for the payment of money due hereunder.

PART 10

MISCELLANEOUS

10.1 Notice

Any notice, direction or other communication required or permitted to be given hereunder must be in writing and will be sufficiently given if delivered or sent by facsimile to the party from whom it is intended at the address of such party set out below. Any notice, direction or other communication so given will be deemed to have been given and to have been received on the day of delivery, if delivered, or on the day of sending if sent by facsimile (provided such day of delivery or sending is a Business Day and, if not, then on the first Business Day thereafter). Each party hereto may change its address for notice by notice given in the manner aforesaid.

10.2 Assignment

Neither party hereto may assign this Agreement or any of its rights hereunder without the prior written consent of the other party, such consent not to be unreasonably withheld.

10.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the party against which such amendment or modification is sought to be enforced.

10.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

10.5 Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter hereof. There are no representations, warranties, covenants or agreements between the parties in connection with such subject matter except as specifically set forth or referred to in this Agreement.

10.6 Counterparts, Facsimile

This Agreement may be executed by the execution of one or more counterparts of the execution page, which will be taken together and constitute the execution page, and one or more of such counterparts may be delivered by facsimile transmission.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement the 31st day of May, 2004.

TERASEN GAS (VANCOUVER ISLAND) INC.

By: *Original signed by Randy Jespersen*

Title: *President*

TERASEN GAS INC.

By: *Original signed by Scott Thomson*

Title: *Vice President of Finance and Regulatory Affairs*

Schedule "A"

Description of Services

Schedule A
Services

On a shared basis, the personnel from the following departmental units of TGI will provide services

(1) **President's Office.** The role and function of the President of TGI is to provide:

(a) governance and liaisons to direct development and implementation of strategic, operational and capital plans;

(b) governance assurance that controls are in place to ensure the Company's are safeguarded and optimized in the best interests of shareholders, customers and other stakeholders;

(c) alignment and communication of the vision and direction to employees and other stakeholders;

(d) executive level succession planning and development to prepare and maintain exceptional leadership; and

(e) act as the principal spokesperson in maintaining close communication with government and the public.

(2) **Finance and Regulatory Affairs**. The role and function of the Finance and Regulatory Affairs department is to provide the following services:

(a) policy direction and oversight of services related to key financial areas including Strategic Planning, Regulatory Affairs, management and financial reporting, and the capital management office;

(b) oversee the understanding, communication and adherence to accounting policies procedures and practices;

(c) lead financial elements of regulatory processes;

(d) establish and execute the process for managing and facilitating the prioritization of all capital expenditures in the TGI companies through the Capital Management Office;

(e) provide high-level, strategic regulatory advice & expertise necessary to ensure the regulatory agenda/platform supports the current and future business needs of the companies;

(f) maintain/enhance the ongoing relationship that is required between TGI/TGVI (via the Regulatory Services department) and key stakeholders in the regulatory environment;

(g) regulatory support from the initial planning stage, including leading consultations with the BCUC and stakeholders and the submission of applications to the BCUC, through to the final implementation and reporting;

(h) development and maintenance of rate structures and the tariff/tariff supplements, and the analysis of cost allocation methodologies, allocated cost of service studies, for gas costs and distribution margin to support rate design applications;

(i) development of strategic and tactical aspects of regulatory platform and creation of applications for revenue requirement, PBR, ROE mechanism, SQI development. Studies and/or Applications may be directed by the BCUC or may be based on corporate strategic requirements;

(j) interpretation, education and communication of new and existing regulatory policies throughout the company, including the development and communication of a corporate regulatory policy;

(k) gathering and analysis of comparative data/competitive intelligence to assess trends within the energy industry & TGI/TGVI position relative to other utilities, particularly those within Canada and the Pacific Northwest;

(l) development of TGI/TGVI financial accounting policies and procedures;

(m) reviewing and maintaining the code of general ledger accounts;

(n) accounting for and validation of all financial statement elements including revenues, cost of gas, deferral accounts, financing costs, bank accounts, the accounting for continuing services and the billing of inter-company transactions;

(o) monthly reporting, variance analysis and year-end forecasting;

(p) external audit coordination and the preparation of non-consolidated financial statements;

(q) annual and multi-year budget processes;

(r) performance measurement and cost analysis; and

(s) asset and Plant accounting.

(3) **Human Resources**. This department is focused on providing HR services to support human resource and related business needs of the operations of the Terasen group of companies. The functional areas and the services they provide are:

(a) advice and guidance to employees and line managers on human resources management activities such as performance management, disability management, succession planning and organizational development;

(b) labour relations advice and guidance including negotiating collective agreements, contract administration and application, grievance and arbitration handling and union relations;

(c) processing activities related to costing time, pay, benefits and pension;

(d) records management and reporting; and

(e) recruitment and staffing.

(4) **Operations Governance and Support**. The role and function of the Operations Governance Support Management team is to provide the following services:

(a) policy direction and oversight of services related to key operational areas including governance of Engineering, Occupational Health & Safety, and the Environment, in addition to Emergency Planning and Public Safety;

(b) management and oversight of services related to project planning and design, system integrity, corrosion control, property services, facility records and geographical information system mapping;

(c) implementation of maintenance of management systems that control and support emergency planning, security and public safety activities to ensure compliance with applicable laws, company policy and industry codes of practice;

(d) ensuring emergency response plans are maintained, updated and tested on a regular basis;

(e) working with governmental and non-governmental agencies to develop and coordinate emergency response protocols;

(f) coordinating the development of security standards and programs to protect TGI facilities and assets;

(g) coordinating and implementing a public safety awareness program and standards to ensure an appropriate level of public safety communication and program delivery to meet "duty of care" and "duty to warn" due diligence;

(h) delivering trades training services to key operations groups within the utility to maintain skill competencies and ensure compliance with laws, policies and industry codes;

(i) maintenance of employee training records;

(j) corporate governance of management systems controlling environmental affairs, employee occupational health & safety, and the design, construction and operation of the gas pipeline system;

(k) monitoring and reporting of compliance with all applicable laws, company policies and industry codes of practice;

(l) advice and direction to Operations groups in support of their accountability to manage specific Environment, Health & Safety risks;

(m) managing a common standards framework to ensure environmental compliance, a safe working environment for employees and consistent, efficient application of standards;

(n) ensure that the workforce meets Workers Compensation Board legislative requirements;

(o) uphold customer and public expectations regarding environmental due diligence and habitat preservation;

(p) responsible for project management and professional services to meet the requirements of managers;

(q) responsible for developing and maintaining a comprehensive Integrity Management Plan for the gas distribution and transmission operating plant assets. Also provides risk-based integrity management services related to operating plant and surrounding natural hazards, principally focused on material defect, corrosion, geotechnical and hydro-technical risks;

(r) responsible for Operation and Maintenance of systems providing cathodic protection to operating plant;

(s) responsible for the planning of lowest cost system improvements for the gas Distribution and Transmission systems, as well as hydraulic scenario analyses for operational enquiries and project development;

(t) responsible for managing all land rights and land tenure issues including property taxation, acquisition & disposal, leases, right of way agreements, environmental reviews and first nations negotiations;

(u) responsible for maintenance and security of all pipeline rights of way; this includes third party crossing permits & inspections, sub-division approvals, vegetation management, right of way patrol, public awareness and encroachment removal;

(v) responsible for completing new mains and service construction drawings and as-built mapping, as well as detailed design drawings for engineering projects as required by the Distribution and Transmission asset managers;

(w) responsible for final data integrity checking of field drawings prior to data entry in the Geographic Information System;

(x) responsible for developing and maintaining the Geographic Information Systems (GIS), and maintaining all records for Distribution and Transmission facilities; and

(y) Responsible for providing Location Records information for underground facilities, as requested through BC One Call.

(5) **Gas Supply and Transmission ("GS&T")**. GS&T provides policy direction and oversight services in addition to business performance management related to key operational areas. The GST department is responsible for:

(a) gas supply which secures the commodity (gas or propane) and ensures it gets to TGI's Transmission network;

(b) transmission which moves the gas to TGI's Distribution network and also manages LNG storage;

(c) business development which ensures that, at a regional level, appropriate capacity and capabilities are available to serve current and future consumers of natural gas;

(d) ensuring there are reliable and secure peaking supplies of natural gas for all core customers at an optimum cost;

(e) arranging natural gas supply to firm and interruptible customers on the distribution system;

(f) providing intra-day balancing supply to stabilize the pressures on the TGI distribution system;

(g) facilitating all gas scheduling and nominations on TGI and third party transmission systems and on the TGI distribution system;

(h) optimizing the value of the natural gas supply portfolio for the benefit of customers on the TGI system;

(i) managing relationships with upstream pipeline companies (Duke, TCPL) to the benefit of TGI's customers;

(j) developing natural gas and propane portfolios for TG and TGVI (Annual Contract Plans);

(k) evaluating supply and asset options (Send out Model);

(l) price risk management for TGI and TGVI;

(m) portfolio and price risk analysis for Gas Supply and Business Development;

(n) provision of Market Information;

(o) execution of the Annual Contract Plans (Resource Stack) to meet core demand in a cost effective manner;

(p) execution of financial hedging transactions;

(q) managing issues upstream/downstream of TGI/TGVI facilities and building relationships with PNW participants;

(r) managing relationships/service delivery with EMS/Transmission customers;

(s) compliance functions;

(t) regional resource planning and other forecasting needs;

(u) maintaining regulatory relationships regarding ongoing Transmission asset management, and managing Transmission safety and pipeline integrity programs;

(v) developing and championing the regional natural gas infrastructure strategy;

(w) identifying, evaluating and developing appropriate growth opportunities; and

(x) managing major third-party transmission shipper relationships.

(6) **Business and Information Technology Services**. This Division provides business services, information technology application and infrastructure management services which enable the operating areas of the company to provide the delivery of utility services. The Division's focus is company-wide and broad in scope.

(a) Policy direction and oversight of services related to key support areas including Business services which is comprised of Facilities services, Purchasing and accounts payable.

(b) Management and oversight of services related to information technology application and infrastructure management services.

(c) Procurement for materials and services.

(7) Accounts Payable.

(a) The accounts payable group is responsible for ensuring vendors are paid accurately and in a timely manner.

(b) Provides administrative support for corporate credit card program.

(c) Facilities Management Services has responsibility for all TGI buildings throughout the service territory. It provides building equipment maintenance, security services and cleaning services. It also arranges and negotiates new space requirements and telecom requests for the organization.

(8) IT Services.

(a) Application Management Services manages the overall data and application architecture for TGI and provides application integration design and delivery services. It is a joint custodian of the TGI Technology Architecture Standards.

(b) Provides application architecture and technology consulting services and ensures application projects are developed according to TGI technology standards.

(c) IT Infrastructure Management plans, forecasts, and designs for future infrastructure capacity requirements and develops and directs the implementation of new technology services at TGI. It is a joint custodian of the TGI Technology Architecture Standards.

(d) IT Infrastructure Management ensures the availability, integrity and security of TGI critical enterprise infrastructure, including: Wide Area Network (WAN), distributed applications/systems, desktop and mobile computer devices, and outsource management.

(9) **Distribution.** The role and function of the Distribution business unit is to provide the following services:

(a) policy direction and oversight of services related to key operational areas including Distribution operations and maintenance, Emergency Management Services, Account Services and Fieldwork, Distribution Operations Support, Measurement Technologies, and Shops, Inventory and Trucking;

(b) general management and oversight of services are focused on delivering a safe, reliable and cost-effective gas distribution system for residential, commercial and industrial customers;

(c) regional managers and front line field Operations and Install managers who are responsible for day-to-day operations in specific geographic areas;

(d) responsible for ensuring that materials and services are manufactured, tested for fitness of use, and distributed to TGI operating and support groups;

(e) measurement technologies is responsible for maintaining the accuracy of metering devices as well as providing energy consumption data to large commercial and industrial customers; and

(f) provide fabrication of critical system components that are installed in the distribution system.

(10) **Marketing**. The primary responsibilities of Marketing are to manage relations with all customer groups and stakeholders; to produce energy use and account growth forecasts; and to manage TGI's internal and external communications requirements. Marketing provides an organizational focus in the management of these responsibilities and in the delivery of marketing services.

Marketing services provided through TGI to TGVI on a shared service basis fall into the following service areas:

(a) responsibility for providing overall policy direction and oversight of services relating to the marketing function, including overseeing the development and implementation of marketing initiatives and programs;

(b) provide overall policy direction and oversight of services relating to residential and small commercial markets;

(c) provides overall policy direction and oversight of services relating to large commercial and industrial markets;

(d) planning and delivery of customer education and communication, product development, and market research;

(e) program development, carries out trade relations activities, manages customer connection policies, and produces marketing communications;

(f) deals with escalated calls from the call centres;

(g) creates messaging for customer education and communication on the topics of rate changes, natural gas prices, competition with alternative fuels, billing issues, customer connection policies and regulatory changes (e.g., gas cost increase, rate design changes);

(h) provides market research activities focus on customer research (e.g., end-use studies), customer satisfaction, safety, and attitudes and opinions around Company initiatives;

(i) oversees both the Main Extension test, and the Company’s service line policies;

(j) evaluates existing offerings to determine if they represent the right mix of customer service and core market cost recovery and the design, negotiation and submission of new an amended services to the British Columbia Utilities Commission;

(k) develops customer energy use and customer additions forecasts;

(l) provides analysis and decision support on longer-term supply/demand and pricing issues, and performs portfolio modeling;

(m) provides overall policy direction and oversight of services relating to TGVI's community and aboriginal relations requirements; and

(n) provides internal and external communications services for the Company, including employee communication and media relations.

Schedule “B”

Pricing

Schedule B
Estimated Pricing

Shared Services Costs to be Allocated	Cost Driver	Annual Total ($000)	Allocation Factors	Allocated ($000)
President	# of Customers	$1,235	9%	$111
Finance & Regulatory	# of Customers	5,313	9%	479
Human Resources	# of Customers	3,119	11.5%	358
Operations Governance & Support	# of Customers/ # of Employees	5,732	9.7%	557
Gas Supply & Transmission	# of Customers	2,186	9%	197
Business & IT Services	# of Customers/ # of Employees	2,940	10.8%	317
Distribution	# of Customers	4,132	9%	372
Marketing	# of Customers	4,132	9%	379
TOTAL		**$28,856**		**$2,770**
Annual Monthly Allocated				**$230.833**

Note the annual allocated amounts shown in this chart are proforma estimates that are subject to year end true-up.